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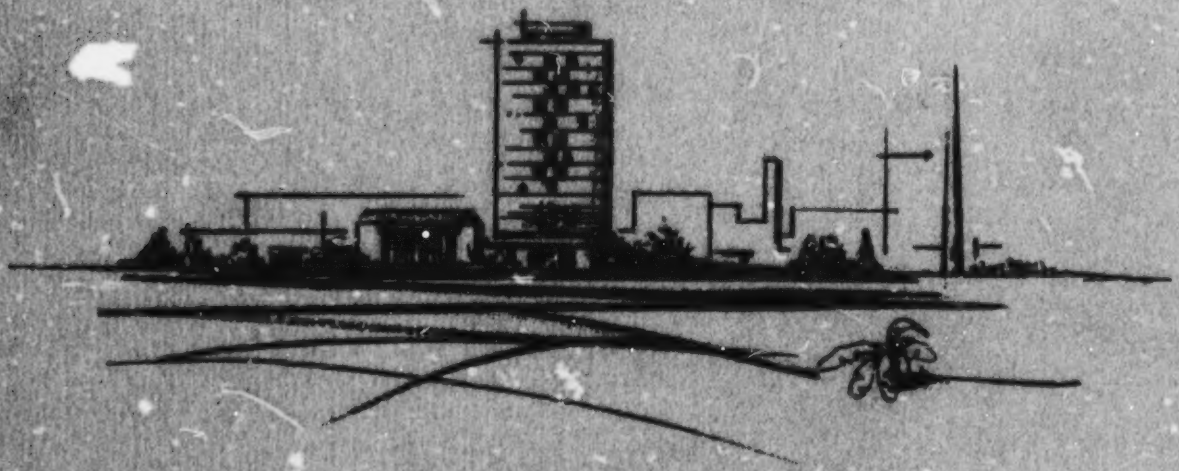

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SUMMARY REPORT

on

A COST-UTILIZATION MODEL FOR SO_2-CONTROL PROCESSES APPLIED TO NEW, LARGE, POWER-GENERATION FACILITIES

(Contract No. PH 86-68-88)

to

INDUSTRIAL CONTROL UNIT
PROCESS CONTROL ENGINEERING PROGRAM
NATIONAL AIR POLLUTION CONTROL ADMINISTRATION
DEPARTMENT OF HEALTH, EDUCATION AND WELFARE

January 17, 1969

by

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and H. E. Carlton

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A COST-UTILIZATION MODEL FOR SO_2-CONTROL PROCESSES APPLIED TO NEW, LARGE, POWER-GENERATION FACILITIES

by

A. W. Lemmon, Jr., B. L. Fletcher, R. E. Schuler,
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January 17, 1969

SUMMARY

In the search for an effective means for decreasing SO_2 emissions resulting from the use of fossil fuels, a number of control techniques have been proposed and are being investigated. To permit comparison of the various potential techniques, a standardized method has been needed. To this end, a cost-utilization model ~~has been~~ was developed which permits the estimation of the incremental cost for control. Specifically, the model ~~has~~ wa been formulated to apply to large fossil-fuel-burning electric power stations using SO_2-control processes which result in the recovery of sulfur or sulfuric acid as a by-product. So that the model will have maximum utility in its present form, provision has been made for the additional alternatives of: remote siting, nuclear generation, and substitute fuels having lower sulfur contents.

The model was ~~as developed and presented in this report~~ has been formulated as a group of algebraic expressions. However, emphasis is placed on the use of computational forms which are provided to assist in organizing input data and performing the required calculations. These forms are accompanied by data (tabular, graphical, and in other forms as well) which permit the selection and entry of the appropriate numerical value in the proper location on a form once a specific SO_2 control or other alternative has been selected. Following the forms in the proper, described sequence results in the prediction of the cost of electricity (as delivered to the distribution network) which would be achieved through application of the specified power-generation alternative. (The costs are not those to the ultimate consumer since other costs - such as those for distribution, billing, etc. - would have to be included.) Also obtained would be predicted values for the amount of sulfur removed, for example. The form provided for the summary of results allows easy comparison of the results obtained for different approaches to SO_2 control for any given service area.

No attempt has been made to include in the present model techniques for determining the "optimum" process for a specified location and size of generating facility. However, by the systematic application of the model to numerous alternatives and a set of locations, the best alternatives will be identified. To illustrate this point, a series of computations for several locations and alternatives were ~~have been~~ performed. Cost of power delivered to a distribution network varied from a low of 3.67 mills/kwhr for local generation in an 800-Mw station serving the Dallas area using natural gas as a fuel to a high of 9.01 mills/kwhr for mine-mouth generation in an 800-Mw station serving the

New York City service area. Costs for control (using the alkalized-alumina process) ranged from a low of 0.26 mills/kwhr for a 2082-Mw station burning 3 percent sulfur coal to serve the Northern Indiana area to a high of 0.53 mills/kwhr for an 840-Mw station burning 3 percent sulfur oil to serve the Baltimore area. For the Northern Indiana example, the control cost would drop to 0.18 mills/kwhr if 5 percent sulfur coal were burned. Costs for control using the Cat-Ox process were also within this range. Costs for nuclear generation were predicted as 5.28 mills/kwhr for the Northern Indiana service area and 5.86 mills/kwhr for the Baltimore and New York City service areas. These were the only nuclear-generation examples computed.

Important indications have been provided by these examples. First, costs for nuclear generation appear to be competitive with those for fossil-fuel generation, particularly in high-cost areas for fuel and labor. Second, with currently available cost information, costs for SO_2 control using processes providing for recovery of sulfur or sulfuric acid in new, large, power-generation facilities should not be expected to exceed 0.5 mills/kwhr. Finally, the use of mine-mouth generation without SO_2 control is not expected to provide a viable alternative because of the high cost of transmission.

It has been concluded that a useful, valid cost-estimating model has been developed for comparing various alternative methods for controlling SO_2 emissions from large, new, power-generation stations. However, there are additional needs for a continuing program to improve the cost data bank and to test further the application of the model to specific locations and sizes of generation facilities. When these immediate steps have been accomplished, then a further look should be taken to evaluate the potential benefits which might accrue from extending the model to include some optimization technique and/or to computerize it.

INTRODUCTION

The problem of atmospheric pollution over the United States is gradually intensifying, and one of the major contributors to this problem is the power-generation industry. Millions of tons per year of noxious gases are emitted by power plants fired with fossil fuels. These noxious gases include sulfur dioxide (SO_2) and nitrogen oxides as major constituents. Recently, intensive interest has been directed at SO_2 as a prime object of current and future control activities.

Predictions of the growth of the power-generation industry and the fossil-fuel-fired segment have been made. For example, the report of National Academy of Science's Committee on Pollution(1)* states that "even with the assumption that, by the year 2000, 50 percent of the U. S. electric generating capacity will be nuclear, it is projected that fossil-fuel-fired electric generating capacity will double by 1980 and redouble by the year 2000. As a consequence, emission quantities would also double by 1980 and redouble by 2000..." With regard to SO_2 emissions it is further stated that, for the case of severe but realistic controls, SO_2 emissions would be expected to increase by 75 percent by 1980 and by an additional 75 percent by 2000. Even with "control at the maximum level that technology will be able to achieve...a 20 percent increase (in SO_2 levels) by 1980 but a 20 percent decrease from that level by 2000..." would be expected.

Thus, the size of the problem is large, and it implies, to some degree, the difficulty of the situation which is faced. For the Federal Government, the National Air Pollution Control Administration has the assignment of encouraging and supporting the development of the necessary control technology. In this Federal program, there is a limit to available funds, manpower, and facilities. As a result, only those processes that show greatest potential promise for control can be investigated. For greatest efficiency, early decisions as to potential promise should be possible. It is this capability for early evaluation and decision which needs to be enhanced and to which this program has been directed.

In planning for the development of SO_2-control processes, two major considerations enter into the decision-making process regarding which processes are likely to be advantageous:

(1) The additional cost of electricity that results from use of a specific SO_2-control process

(2) The utility of the SO_2-control process in terms of its applicability to specific power plants and the implications this has regarding the amount of SO_2 that will be prevented from entering the atmosphere.

There are other factors that enter into the development-decision process, such as the evaluation of technical feasibility, but this cost-utilization model is concerned with evaluation of only those factors listed above. "Benefits" cannot be evaluated at the present state of our knowledge and, thus, so-called cost-benefit factors cannot be computed. Arbitrary levels of SO_2 concentration in stack gas will form the basis for the comparisons to be made.

---

*References are listed on page 131.

It should be noted here that the model also contains provision for evaluating the cost and utility implications of other approaches to SO_2 control other than the treatment of flue gas. The use of low-sulfur coal can be evaluated by suitable adjustment of fuel costs, and the remote-location approach can be costed by adjustment of transmission, fuel, and other cost elements that depend upon location. Comparison with costs achieved by nuclear generation is also possible.

MODEL ORGANIZATION AND PROCEDURE

General Description of Model

The model developed in this program is designed to enable the analysis of the incremental cost of approaches to controlling SO_2 emissions of large fossil-fuel-burning electric power plants. The model also contains provision for evaluating the costs of approaches to SO_2 control other than the treatment of flue gas. For example, the use of low-sulfur coal can be evaluated by suitable adjustment of fuel costs, or a remote-siting approach can be considered by inclusion of transmission costs and the adjustment of fuel and other cost elements that depend upon location. The incremental cost is ultimately expressed in terms of a "mills/kwhr" value above that for power generation without an SO_2-control approach.

The model is concerned with power-generation costs only, except in the case when transmission costs are included because remote siting is being considered as an alternative approach to SO_2 control. The costs developed, then, are not those to the ultimate consumer, since other costs – such as those for distribution – would have to be included.

The model is formulated as a group of algebraic expressions. However, emphasis is placed on use of the forms that are also provided to assist in organizing input data and performing the required calculations. Use of these forms helps to insure that the required cost elements are considered, that the proper computations are completed, and that records are made of the analysis. The form provided for the summary of results allows easy comparison of the results obtained for different approaches to SO_2 control for the power plant of interest. The input data are obtained from curves showing "cost-estimating relationships" (CER's) or tables provided in the section on Cost Elements for Fossil-Fuel-Burning Power Plants.

Costs are regarded as falling in the two broad categories – nonrecurring and recurring. Nonrecurring costs are those required for initial equipment installation and start-up and, if applicable, the cost of additional-equipment installation that may take place after the plant is in operation; for example, an additional power-generation unit might be installed after several years of operation of the first unit. Recurring costs are those costs for fuel, operations, maintenance, and other annual expenses. Determination of the nonrecurring and the annual recurring costs permits the analyst to generate plots such as those shown in Figure 1. The nonrecurring cost is shown as an initial cost at the start of the first year of operation, and the recurring-cost cumulative total is plotted for each subsequent year of the time period of interest.

Use of the nonrecurring-recurring cost approach avoids the problems associated with determining the annual charges that arise because of the initial investment. However, in order to determine an incremental "mills/kwhr" value that reflects both nonrecurring and recurring costs, it is necessary to "annualize" the nonrecurring costs. This requires consideration of "financial factors" such as the cost of capital, the period and type of depreciation, and income-related taxes. Provision is made in the model for including such "financial factors" as an annual cost that is added to other recurring costs. This sum of the annual costs divided by the sum of net energy available for distribution for the planning period provides the desired "mills/kwhr" value.

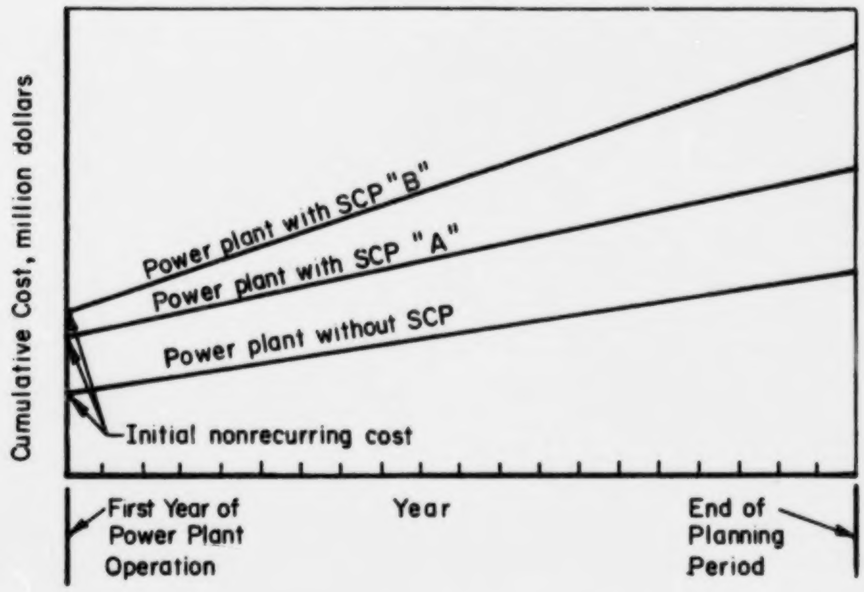


FIGURE 1. CUMULATIVE NONRECURRING AND RECURRING COSTS FOR POWER PLANT WITH AND WITHOUT AN SO_2-CONTROL PROCESS (SCP)

The model permits analysis on a yearly basis or on a cumulative total basis for a specified planning period. In cases where the annual costs do not vary, the analysis of only the nonrecurring cost and 1 year's recurring cost is required. However, if changes in "capacity factor"*, power-generation capacity, fuel characteristics, or other factors are expected to occur after the first year of operation, then annual costs must be adjusted accordingly. The model makes provision for this by allowing for annual entries of recurring costs.

The concern of this model is with future costs, and there are many problems associated with translating past cost experience into a future estimate. To avoid some of these problems, future cost estimates are made in terms of current dollars. Also, provision has been made for the adjustment of historic construction cost data to current dollars. (see p 40.)

This program has not been primarily concerned with generating the detailed installation, operation, and maintenance costs for SO_2-control equipment and the associated by-product plant, although a limited amount of work has been performed in this area to help guide model-development efforts. The costs for the SO_2-control approach are entered as increments to the nonrecurring and recurring costs of power-plant construction and operation. This is accomplished by one of the following procedures:

(1) The nonrecurring and recurring costs for the SO_2-control equipment and by-product plant are entered in combination or separately on the appropriate forms to enable addition to the nonrecurring and recurring costs of the power plant. If the nonrecurring and recurring costs for

---

* See p 62 for definition of "capacity factor".

the power plant without SO_2 control are influenced by the use of SO_2-control devices – for example, if boiler-plant modifications are required – then these costs are adjusted accordingly. Provision is also made for allowing credits for the sale of by-product.

(2) If a fuel change is used for SO_2 control, the incremental cost is determined by evaluating the recurring fuel costs resulting from changes in fuel price and consumption, the latter being influenced by possible changes in heat rate of the power plant and heat content of the fuel.

(3) If remote siting is considered as an option to the use of an SO_2 control process, then the nonrecurring and recurring costs for power transmission are considered.

Provision is made in the model for determining the total weight of sulfur contained in the fuel burned. If the analyst knows or assumes an efficiency of SO_2 removal of the SO_2-control process, he can then compute the amount of sulfur removed that would otherwise be released to the atmosphere as SO_2. Such data, along with the incremental costs required for the SO_2-control process, then permit the analyst to calculate the cost per ton of sulfur prevented from entering the atmosphere as SO_2.

An important consideration in the model is the time period to be examined in the cost analysis. Ideally, cost data starting with the first significant research expenditure for the SO_2-control process along with all other nonrecurring and recurring costs for the power plant and the SO_2-control-process facilities – with credits for the sale of by-products – and continuing throughout the life of the power plant would be considered. However, this ideal must be tempered with the realization that cost uncertainties increase with the extent of the time horizon. For this reason, the position taken is that cost projections beyond a 20-year plant operation period are not meaningful in terms of evaluating the relative economics of SO_2-control-process alternatives.

Additional discussion of the background and other considerations that influenced the structure of the model are found in Appendix A.

Model Details

The details of the model are described below. This description is organized around a discussion of the equations used for calculations and the forms that have been developed for the analyst to use in organizing input data, performing the required calculations and summarizing results. Reference is also made to the appropriate section of the report for obtaining the required input data.

Figure 2, Simplified Flow Chart of Model, provides an overview of the type and sequence of computations used in the model. The applicable equations and forms used for each calculation are indicated. Table 1 lists the forms provided for the analyst, and Table 2 supplies a summary of the equations used and definitions of symbols in the equations. The figure number for each form used is indicated, and the text accompanying each figure should be referred to in order to understand what alternative computations can be made according to the type of available input data. Some of the terms of the equations shown in Table 2 are set equal to zero according to the requirements of the

TABLE 1. FORMS PROVIDED FOR THE ANALYSIS

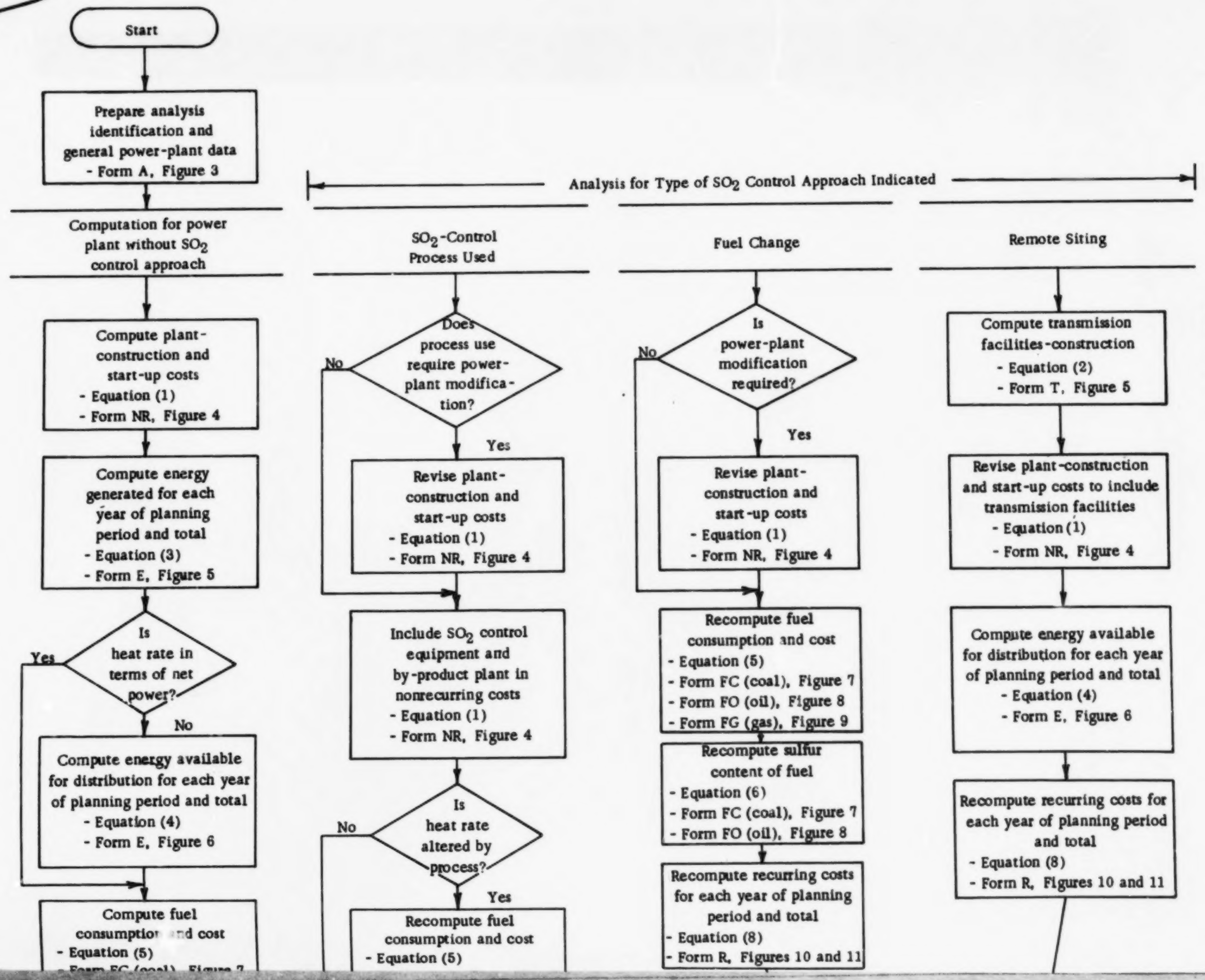
	Title
Form A	ANALYSIS IDENTIFICATION AND GENERAL POWER-PLANT DATA
Form NR	PLANT CONSTRUCTION AND START-UP COSTS
Form T	TRANSMISSION-FACILITIES CONSTRUCTION COSTS
Form E	ENERGY GENERATED AND ENERGY AVAILABLE FOR DISTRIBUTION
Form FC	COAL CONSUMPTION AND COST AND SULFUR CONTENT SUMMARY
Form FO	OIL CONSUMPTION AND COST AND SULFUR CONTENT SUMMARY
Form FG	GAS CONSUMPTION AND COST
Form R	RECURRING COST SUMMARY
Form S	SUMMARY OF RESULTS OF ANALYSIS

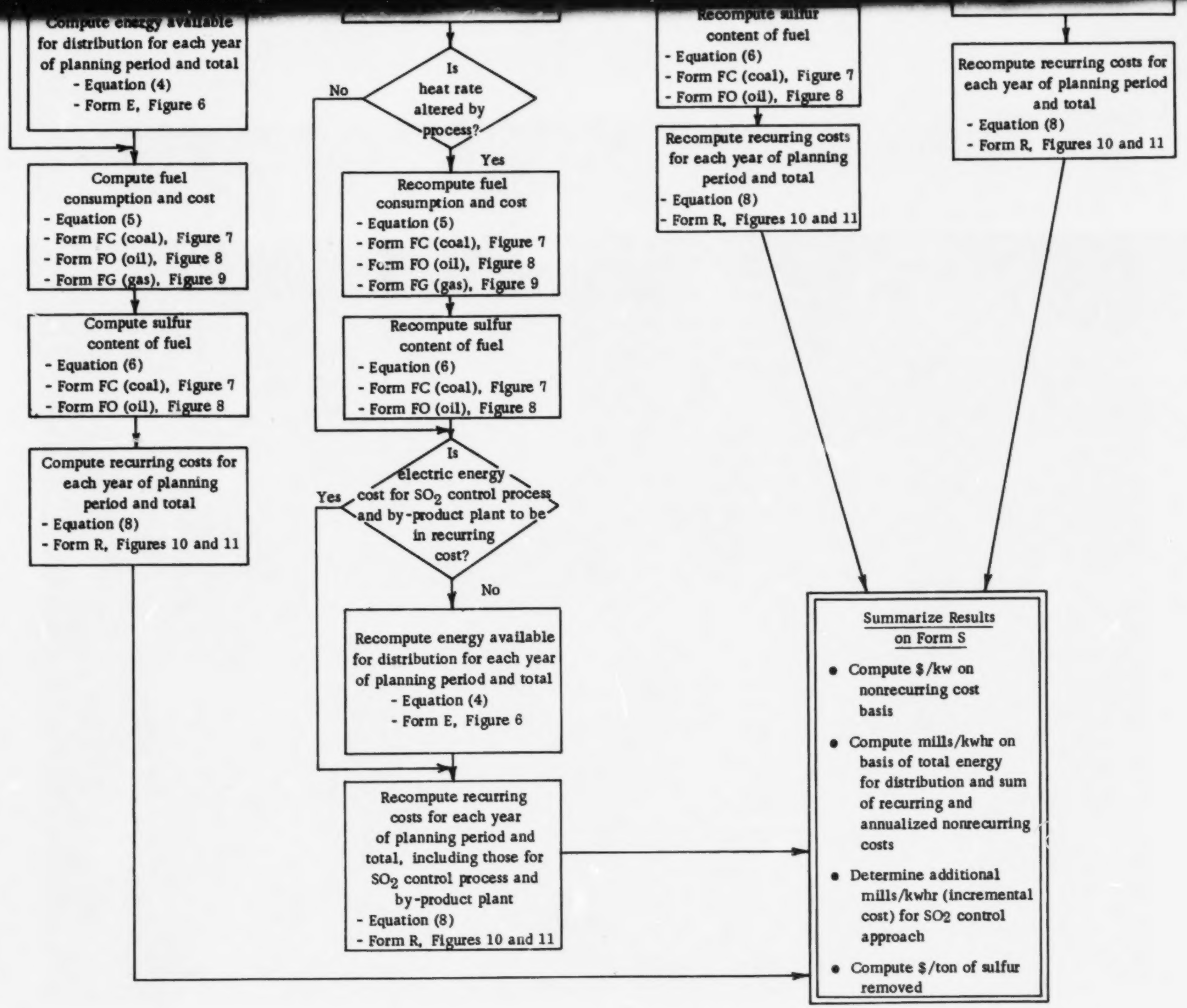
particular analysis; for example, Equation (1), which is used to determine the sum of nonrecurring costs (T_{NR}), would be used with C (SO_2-control-process equipment costs) and B (by-product-plant construction costs) set equal to zero in the case where an SO_2-control process is not applied.

In general, the analyst must first establish the nonrecurring and recurring costs of the power plant without an SO_2-control approach. The cost analysis is then repeated for the various control options of interest. By "annualizing" the nonrecurring costs, adding these to the recurring costs, summing the resultant for the planning period, and then dividing by the total electrical energy made available for distribution during the planning period, a "mills/kwhr" value is obtained. This value for the various control options can be compared to that for the power plant without SO_2 control – the difference in these values is an overall incremental cost for SO_2 control.

The data generated also permit the calculation of a dollar per kilowatt value on the basis of nonrecurring costs and the nameplate generating capacity of the power plant. Another calculation provided for is that to determine the cost per ton of sulfur removed that would otherwise enter the atmosphere as SO_2.

A capability required of this model is to permit the analyst to introduce incremental costs for SO_2-control approaches. This is accomplished by introducing nonrecurring and recurring costs as entries in the various forms to be discussed. The analyst has considerable freedom in the amount of detail shown for such incremental costs. For example, he can enter separate costs for the operations, maintenance, taxes (non-income), and insurance when entering recurring costs for the SO_2-control equipment


Start
Prepare analysis identification and general power-plant data
- Form A, Figure 3
Analysis for Type of SO_2 Control Approach Indicated
Computation for power plant without SO_2 control approach
SO_2-Control Process Used
Fuel Change
Remote Siting
Compute plant-construction and start-up costs
- Equation (1)
- Form NR, Figure 4
Compute energy generated for each year of planning period and total
- Equation (3)
- Form E, Figure 5
Is heat rate in terms of net power?
Yes
No
Compute energy available for distribution for each year of planning period and total
- Equation (4)
- Form E, Figure 6
Compute fuel consumption and cost
- Equation (5)
- Form FC (coal), Figure 7
Does process use require power-plant modification?
No
Yes
Revise plant-construction and start-up costs
- Equation (1)
- Form NR, Figure 4
Include SO_2 control equipment and by-product plant in nonrecurring costs
- Equation (1)
- Form NR, Figure 4
Is heat rate altered by process?
No
Yes
Recompute fuel consumption and cost
- Equation (5)
Is power-plant modification required?
No
Yes
Revise plant-construction and start-up costs
- Equation (1)
- Form NR, Figure 4
Recompute fuel consumption and cost
- Equation (5)
- Form FC (coal), Figure 7
- Form FO (oil), Figure 8
- Form FG (gas), Figure 9
Recompute sulfur content of fuel
- Equation (6)
- Form FC (coal), Figure 7
- Form FO (oil), Figure 8
Recompute recurring costs for each year of planning period and total
- Equation (8)
- Form R, Figures 10 and 11
Compute transmission facilities-construction
- Equation (2)
- Form T, Figure 5
Revise plant-construction and start-up costs to include transmission facilities
- Equation (1)
- Form NR, Figure 4
Compute energy available for distribution for each year of planning period and total
- Equation (4)
- Form E, Figure 6
Recompute recurring costs for each year of planning period and total
- Equation (8)
- Form R, Figures 10 and 11


Compute energy available for distribution for each year of planning period and total
- Equation (4)
- Form E, Figure 6
Compute fuel consumption and cost
- Equation (5)
- Form FC (coal), Figure 7
- Form FO (oil), Figure 8
- Form FG (gas), Figure 9
Compute sulfur content of fuel
- Equation (6)
- Form FC (coal), Figure 7
- Form FO (oil), Figure 8
Compute recurring costs for each year of planning period and total
- Equation (8)
- Form R, Figures 10 and 11
Is heat rate altered by process?
No
Yes
Recompute fuel consumption and cost
- Equation (5)
- Form FC (coal), Figure 7
- Form FO (oil), Figure 8
- Form FG (gas), Figure 9
Recompute sulfur content of fuel
- Equation (6)
- Form FC (coal), Figure 7
- Form FO (oil), Figure 8
Is electric energy cost for SO2 control process and by-product plant to be in recurring cost?
Yes
No
Recompute energy available for distribution for each year of planning period and total
- Equation (4)
- Form E, Figure 6
Recompute recurring costs for each year of planning period and total, including those for SO2 control process and by-product plant
- Equation (8)
- Form R, Figures 10 and 11
Recompute sulfur content of fuel
- Equation (6)
- Form FC (coal), Figure 7
- Form FO (oil), Figure 8
Recompute recurring costs for each year of planning period and total
- Equation (8)
- Form R, Figures 10 and 11
Recompute recurring costs for each year of planning period and total
- Equation (8)
- Form R, Figures 10 and 11
Summarize Results on Form S
• Compute $/kw on nonrecurring cost basis
• Compute mills/kwhr on basis of total energy for distribution and sum of recurring and annualized nonrecurring costs
• Determine additional mills/kwhr (incremental cost) for SO2 control approach
• Compute $/ton of sulfur removed

A-55781

FIGURE 2. SIMPLIFIED FLOW CHART OF MODEL

Note: Referenced equations are shown in Table 2.

B

TABLE 2. SUMMARY OF EQUATIONS USED IN MODEL AND SYMBOL DEFINITIONS

Equation	Symbol	Definition
(1) $T_{NR} = P + S + C + B + T$		
	T_{NR}	Total nonrecurring construction and start-up costs
	P	Power-plant construction cost
	S	Start-up cost
	C	SO_2-control-process equipment cost
	B	By-product-plant construction cost
	T	Transmission-facilities construction cost
(2) $T_T = I + E + M_1D_1 + M_2D_2$		
	T_T	Nonrecurring cost for transmission facilities
	I	Cost of structures and improvements at the power plant
	E	Cost of station equipment
	M_1	Number of miles of overhead transmission lines
	D_1	Cost per mile for overhead transmission lines
	M_2	Number of miles of underground transmission lines
	D_2	Cost per mile for underground transmission lines
(3) $E_{T,i} = 8.766 \times 10^{-5} \times Y_i \times P_{N,i}$		
	E_T	Total energy generated, billions of kwhr
	Y	Capacity factor, %
	P_N	Nameplate generating capacity, Mw
	i	Subscript to indicate ith year

TABLE 2. (Continued)

Equation	Symbol	Definition
(4) $E_{NET,i} = E_{T,i} - E_{PP,i} - E_{SCP,i} - E_{BPP,i} - E_{TR,i}$		
	E_{NET}	Energy available for distribution
	E_T	Total energy generated
	E_{PP}	Energy consumption in power plant
	E_{SCP}	Energy required for SO_2-control equipment
	E_{BPP}	Energy required for by-product-plant operation
	E_{TR}	Transmission energy losses
	i	Subscript to indicate ith year
(5) $F_i = K \times C_i \times E_{T,i} \times H_i \times U_i^{-1}$		
	F	Annual fuel cost
	K	Multiplier for adjusting units
	C	Cost of fuel (coal), \$/ton
	E_T	Total energy generated, billions of kwhr
	H	Heat rate, Btu/kwhr
	U	Heat content of fuel (coal), Btu/lb
	i	Subscript to indicate ith year
(6) $W_{S,i} = W_{P,i} \times W_{F,i} \times 10^{-2}$		
	W_S	Weight of sulfur in fuel, tons
	W_P	Sulfur content, percent by weight
	W_F	Weight of fuel consumed, tons
	i	Subscript to indicate ith year

TABLE 2. (Continued)

Equation	Symbol	Definition
(7) $T_{F,i} = T_{M,i} + DT_{T,i}$		
	T_F	Fob plant cost per ton of coal, \$/ton
	T_M	Cost of coal at mine, \$/ton
	D	Distance from mine to power plant, miles
	T_T	Transportation charge, \$/ton-mile
	i	Subscript to indicate ith year
(8) $T_{R,i} = F_i + \sum_{n=1}^{4} (O_i + M_i + T_i + I_i)_n - C_i$		
	T_R	Total annual recurring cost
	F	Fuel cost
	O	Operations cost
	M	Maintenance cost
	T	Taxes (nonincome)
	I	Insurance cost
	n	Subscript applies as follows:
		n = 1, power plant
		n = 2, transmission facilities
		n = 3, SO_2-control-process equipment
		n = 4, by-product plant
	C	Income from sale of by-product
	i	Subscript to indicate ith year

and by-product plant; or he can use one cost entry that covers all recurring cost elements for both the control equipment and by-product plant. This flexibility is considered desirable in anticipation of the types of analyses expected to be of interest.

It is worthwhile to point out here some of the important possibilities the analyst should have in mind when performing the analysis:

(1) The application of an SO_2-control process may require modification of the power-plant design, and the analyst should consider whether this will have an impact on nonrecurring costs for the power plant. Fuel changes may also affect these costs.

(2) If the recurring costs for the SO_2-control equipment and by-product-plant operation do not include the cost of electrical energy used, then this energy should be subtracted from that available for distribution.

(3) Fuel consumption should be adjusted to allow for any changes in heat rate resulting from the application of the SO_2-control process.

Figure 2 introduces these considerations by asking questions at the appropriate place in the analysis.

Forms

The forms provided are designed to assist the analyst in organizing input data and performing the required calculations. Each line item on these forms reminds the analyst of what is needed to complete the analysis. The Data Source column provided on several of the forms shows how or where the entry for a specific line is determined. Where appropriate, the completed forms also provide a good record of what was considered or ignored in a particular analysis. As shown in Figure 2, each analysis requires a Form A, Analysis Identification and General Power Plant Data and a Form S, Summary of Results of Analysis. The number and type of other forms used is determined by the number of SO_2-control options considered.

Provision is made on each form for analysis identification, and the entry of notes and other information that is expected to assume increasing importance as analytical results accumulate and the need develops to recall the details of various analyses.

Now consider the details regarding the calculations and the completion of each form.

Analysis Identification and General Power-Plant Data

Form A, Analysis Identification and General Power-Plant Data (Figure 3), is used to identify the analysis and to provide general data regarding the power plant, indicate the planning period of interest, and specify what SO_2-control processes are being considered. The nameplate generating capacity of the power-generation units is shown in the form, and provision is made for showing when the initial and subsequent power-generation units will be placed in operation and when construction will start, the latter time being of interest when the analyst must consider the availability date of a SO_2-control process. The capacity factor assumed is also shown on this form, but if it is desirable to vary this during the planning period, this is shown on Form E (see page 21).

The type or types of fuel are identified. (If more than one type of fuel is used, the fraction of time each type is used must be indicated.) The permissible SO_2 concentration is shown along with the percentage of sulfur removed.

Other entries are for bookkeeping purposes, such as a list of the various forms used in the particular analysis.

Plant Construction and Start-Up Costs

The total nonrecurring construction and start-up costs (T_{NR}) are determined from the equation

$$T_{NR} = P + S + C + B + T \quad , \tag{1}$$

wherein the following definitions apply:

Symbol	Definition
P	Power-plant construction cost
S	Start-up cost
C	SO_2-control-process equipment cost
B	By-product-plant construction cost
T	Transmission-facilities construction cost

Form NR, Plant Construction and Start-Up Costs (Figure 4), provides a format for accumulating these costs. In addition, the costs for the power-plant subsystems that determine power-plant construction costs are listed on this form. These subsystems are defined the same as in the Uniform System of Accounts published by the Federal Power Commission (see Reference 2, p 43). This is done to facilitate use of data provided to the Federal Power Commission in this format. Also, data regarding these subsystem costs may be needed because of cost revisions that result from the need to modify power-plant subsystems when installing SO_2-control-process equipment. However, in those cases where only the overall power-plant cost is known or of interest, only the entry for the total cost of the power plant (P) is entered on the line Power Plant Subtotal shown on Form NR.

C and B or T may be set equal to zero in specific analyses according to the option being analyzed. A value would be used for T in the case where the remote-siting option is being considered. Only the subtotal for C + B is shown on Form NR for those cases where C and B are not costed separately.

Start-up costs (S) have been included in the nonrecurring costs to remind the analyst of their possible importance in the cases where SO_2-control processes are first applied to large power plants. However, data regarding start-up costs are not yet available.

Data regarding plant-construction costs are discussed in the section on Initial Plant Costs. Transmission-facilities construction costs are discussed in the section on

Power Plant Identification: ____________________

Location: ____________________ **Service Area:** ____________

Year of Start of Construction: __________

Generating Unit No.	Nameplate Capacity, megawatts	First Year of Operation
________	________	________
________	________	________
________	________	________
________	________	________

Type of Fuel	Fraction of Time Each Type Used
Coal	________
Oil	________
Gas	________

Planning Period Considered: ____________ **Through** ____________

Capacity Factor, %, Average: __________*

SO_2 Control Processes Considered: ____________________

____

Permissible SO_2 Concentration Used in Analysis: ______ppm

Sulfur Removal: ______%

Forms Used For Analysis (list by Form and Analysis Identification No.)

______	______	______	______	______	______
______	______	______	______	______	______

Notes: ____________________

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***If the capacity factor varies during planning period, show on Form E.**

Analysis Identification: __________

Date Prepared: __________

Analyst: ______________

FIGURE 3. FORM A – ANALYSIS IDENTIFICATION AND GENERAL POWER-PLANT DATA

Item	FPC Account No.	(1)	(2)	Cost, millions of dollars
Land and Land Rights	310			
Structures and Improvements	311			
Boiler-Plant Equipment	312			
Engines	313			
Turbogenerator Units	314			
Accessory Electrical Equipment	315			
Miscellaneous Power Plant Equip.	316			
Power Plant Subtotal				
Transmission-Facilities Construction Cost				
SO_2-Control-Process Equipment				
By-Product Plant				
SO_2 Control Process and By-Product Plant Subtotal				
Start-Up Costs				
Other (Specify)				
TOTAL				

(1) Indicate number of power generating units considered where appropriate.

(2) Check in this column if cost includes consideration of modifications required for SO_2 control process.

Notes:

Analysis Identification

Date Prepared

Analyst

FIGURE 4. FORM NR – PLANT-CONSTRUCTION AND START-UP COSTS

Transmission Costs. SO_2-control process equipment and by-product-plant construction costs are discussed in the section on Sulfur Dioxide Control Devices.

Transmission-Facilities Construction Costs

If the remote-siting option is to be considered, then the nonrecurring and recurring costs for transmission facilities should be included in the analysis. Form T, Transmission Facilities Construction Costs (Figure 5), provides for the analysis of these costs. Note that two approaches are allowed for in the computation of nonrecurring transmission-line costs. The first is based on the use of dollars-per-mile data. The equation used to compute the nonrecurring cost for transmission facilities (T_T) in this case is

$$T_T = I + E + M_1D_1 + M_2D_2 \quad , \qquad (2)$$

wherein the following definitions apply:

Symbol	Definition
I	Cost of structures and improvements at the power plant [FPC Account No. 352, Reference (2), p 54]
E	Cost of station equipment [FPC Account No. 353, Reference (2), p 54]
M_1	Number of miles of overhead transmission lines
D_1	Cost per mile for overhead transmission lines
M_2	Number of miles of underground transmission lines
D_2	Cost per mile for underground transmission lines

If there are significant differences in the cost of various sections of overhead or underground transmission lines, then additional MxD terms can be included to reflect this situation. The sum of the M-terms should add up to the total transmission distance.

Because of the nature of data presently available, cost elements I and E are considered as one cost and are entered on the "Terminal and Other Equipment" line of Form T. Data for these costs are discussed in the section on Transmission Costs.

If the case should arise where per-mile costs for transmission lines are not available or considered inadequate, then it may be necessary to evaluate the component costs. This can be done on the basis of FPC account numbers [Reference (2), p 54], and Form T makes provision for this alternative calculation. The line items shown under Alternative Transmission Facilities Cost Computation are defined in detail on pp 54-55 of Reference (2). However, the cost-per-mile approach to costing is more convenient, and the component-costing approach is included only to provide the analyst with an alternative if cost-per-mile data are lacking.

Item	Cost, millions of dollars

Transmission Facilities:

Overhead Line: _____ (miles) x _____ ($/mile) x 10^{-6} = _______

Overhead Line: _____ (miles) x _____ ($/mile) x 10^{-6} = _______

Underground Line: _____ (miles) x _____ ($/mile) x 10^{-6} = _______

Underground Line: _____ (miles) x _____ ($/mile) x 10^{-6} = _______

Total Transmission Line _______

Terminal and Other Equipment _______

Total Transmission Facilities _______

Alternative Transmission Facilities Cost Computation:

Item	FPC Account Number	
Land and Land Rights	350	_______
Clearing Land and Rights of Way	351	_______
Structures and Improvements	352	_______
Station Equipment	353	_______
Towers and Fixtures	354	_______
Poles and Fixtures	355	_______
Overhead Conductors and Devices	356	_______
Underground Conduit	357	_______
Underground Conductors and Devices	358	_______
Roads	359	_______

Total Transmission Facilities (Alternative) _______

Notes: ____

____

____

Analysis Identification _______________
Date Prepared _______________
Analyst _______________

FIGURE 5. FORM T – TRANSMISSION FACILITIES CONSTRUCTION COSTS

The recurring costs for transmission facilities – operations, maintenance, taxes (nonincome), and insurance are entered in Form R, Recurring Cost Summary. (See section on Recurring Costs.)

Energy Generated and Energy Available for Distribution

In order to determine the fuel consumed, it is necessary to calculate the total energy generated. Also, in order to calculate the mills/kwhr cost for energy delivered to the distribution network, it is necessary to determine the energy available for distribution as determined by the energy consumption within the power plant, energy requirements of the SO_2-control equipment and by-product plant, and the energy losses in the transmission equipment, if remote siting of the power plant is to be considered.

The total energy generated during the i^{th} year is calculated by the following equation:

$$E_{T,i} = 8.766 \times 10^{-4} \times Y_i \times P_{N,i} \quad . \tag{3}$$

Terms of the equation are defined as follows:

Symbol	Definition
E_T	Total energy generated, billions of kwhr
Y	Capacity factor*, %
P_N	Nameplate generating capacity, Mw

The 8.766×10^{-4} factor allows for the number of hours in the year and adjusts for the units used. The values calculated for $E_{T,i}$ are entered on the appropriate fuel-consumption summaries (Form FC, FO, or FG – see following section) to enable computation of total fuel consumption. The energy calculations are made by use of Form E, Energy Generated and Energy Available for Distribution (Figure 6).

The calculation of energy available for distribution is based on the following relationship for the i^{th} year:

$$E_{NET,i} = E_{T,i} - E_{PP,i} - E_{SCP,i} - E_{BPP,i} - E_{TR,i} \quad . \tag{4}$$

The terms of this equation are defined as follows:

---

*Capacity factor is defined here as 100 times the ratio of energy generated per year to the product of nameplate generating capacity times the number of hours in the year (8766 hr/yr).

Year →

Energy Generated

Line No.	Item	Units	Entry Source*																					Total
1	Nameplate Capacity	Megawatts	Form A																					
2	Capacity Factor	Percent	Form A																					
3	Energy Generated	Billion kwhr	$8.766 \times 10^{-5} \times (1) \times (2)$																					

Energy for SO_2 Control Equipment and By-Product Plant

4	Power for SO_2 Control Equipment	Megawatts	Input																					
5	Power for By-Product Plant	Megawatts	Input																					
6	Total	Megawatts	(4) + (5)																					
7	Energy Required	Billion kwhr	$8.766 \times 10^{-5} \times (6) \times (2)$																					

Transmission Energy Loss

8	Power Loss	Megawatts	Input																					
9	Energy Loss	Billion kwhr	$8.766 \times 10^{-5} \times (8) \times (2)$																					

Other (specify)

10		Megawatts	Input																					
11		Billion kwhr	$8.766 \times 10^{-5} \times (10) \times (2)$																					

Energy Available for Distribution

12	Energy Available	Billion kwhr	(3) - (7) - (9) - (11)																					

* Numbers in parentheses refer to line number on form.

Notes:____________________

Analysis Identification________

Date Prepared________

Analyst________

FIGURE 6. FORM E - ENERGY GENERATED AND ENERGY AVAILABLE FOR DISTRIBUTION

Symbol	Definition
E_{NET}	Energy available for distribution
E_T	Total energy generated
E_{PP}	Energy consumption in power plant
E_{SCP}	Energy required for SO_2-control equipment
E_{BPP}	Energy required for by-product-plant operation
E_{TR}	Transmission-energy losses

Provision is made for calculation of energy available on an annual basis in order to accommodate the installation of additional generating capacity or a change in capacity factor after the first year of operation. However, it is expected that many cases will be analyzed by use of an average value throughout the planning period. The calculation of energy on the basis of the above equation implies that the electrical-energy requirements for SO_2-control and by-product-plant operation have been taken into account, so the cost of this energy should not be added to the recurring costs assigned to the SO_2-control process and by-product plant. However, the analyst has the option of including the electrical-energy charges in the recurring operations costs for the SO_2-control process and by-product-plant operation, but the $E_{SCP,i}$ and $E_{BPP,i}$ terms should be omitted from the evaluation of $P_{NET,i}$ in this case.

The heat rate (Btu/kwhr) data used to calculate fuel consumption and costs is based on net generation. This means that the fuel costs for internal power consumption within the plant are allowed for, so, further consideration is not given to energy consumption within the plant when heat-rate data of this type are used. Form E contains a line Other Losses that can be used to subtract out energy consumed within the power plant, if such data become available. However, if this is done, care should be taken to adjust the heat rate accordingly.

Fuel Consumption, Cost, and Sulfur Content

It has been reported that fuel costs accounted for 78 percent of annual production expenses in 1966 [Reference (3)]; hence, this is a major recurring expense item. Also, the use of low-sulfur fuels is a possible alternative to installation of an SO_2-control process, but this usually implies higher fuel expenses, so the comparative costs require evaluation.

Annual fuel costs for the i^{th} year (F_i) are found by use of the following expression:

$$F_i = K \times C_i \times E_{T,i} \times H_i \times U_i^{-1} , \tag{5}$$

where K is a constant representing the multiplier required to adjust the units used for the other factors in the equation. The other factors are defined as follows:

Symbol	Definition (for Coal)
C	Cost of fuel, \$/ton
E_T	Total energy generated, billions of kwhr
H	Heat rate, Btu/kwhr
U	Heat content of fuel, Btu/lb

If oil is burned, U_i is expressed as Btu/gal; for gas, U_i is expressed as Btu/cu ft. Note that the forms provided for calculation of fuel costs also make provision for the use of fuel costs stated in terms of ¢/million Btu. If more than one fuel is used at a plant, then separate calculations for each fuel would be made on the basis of percent of total energy generated by each fuel.

Form FC, Coal Consumption and Cost and Sulfur Content Summary (Figure 7), is provided for the calculation of coal costs on an annual basis. (Forms FO, Figure 8, and FG, Figure 9, are for oil and gas, respectively.) By suitable input-data adjustments, it is possible to determine the effects on recurring fuel costs of changes in capacity factor, incorporation of additional generating units after the first year of operation, and changes in the cost and heat content of the fuel as a function of time. However, in many cases, it is expected that it will be adequate to use an average value that applies throughout the planning period considered. The form used for calculating fuel consumption and cost is also a convenient place to calculate the amount of sulfur contained in the fuel. Provision is made for this calculation on Forms FC and FO. (The sulfur content of gas is usually considered to be negligible.) The weight of the sulfur in the fuel consumed during the i^th^ year is obtained from the relationship:

$$W_{S,i} = W_{P,i} \times W_{F,i} \times 10^{-2} \quad . \qquad (6)$$

The terms used are defined as follows:

Symbol	Definition
W_S	Weight of sulfur in fuel, tons
W_P	Sulfur content, weight percent
W_F	Weight of fuel consumed, tons

If sulfur weight is to be given in long tons, the weight obtained by this expression is divided by 1.12.

The Energy Generated entry on Forms FC, FO, and FG is obtained from Form E. The calculation of fuel consumption, cost, and sulfur content then proceeds by performing the arithmetic operations indicated on the form to complete each successive line.

In the case of coal, the cost should be that for "as burned" as distinguished from "fob plant". This distinction is made because the fob plant cost of coal is the mine price plus freight charges, while the as-burned cost includes the cost of handling to place the coal in the boiler room bunkers; also, the as-burned cost includes a debit or credit for ash disposal. However, the as-burned prices shown are also influenced by

Year →

Coal Consumption

Line No.	Item	Units	Entry Source*																					Total
1	Energy Generated	10^9 kwhr	Form E, Line (3)																					
2	Heat Rate	10^3 Btu/kwhr	Input																					☒
3	Total Btu Required	10^{12} Btu	(1) x (2)																					
4	Btu/Lb of Coal	10^3 Btu/lb	Input																					☒
5	Btu/Ton of Coal	10^6 Btu/ton	2.0 x (4)																					☒
6	Coal Consumed	10^6 tons	(3) ÷ (5)																					

Coal Cost

If cost in ¢ / million Btu

7	"As-Burned" Cost	¢ / million Btu	Input																					☒
8	Total Cost	Million $	(3) x (7) x 10^{-2}																					

If cost in $/ton

9	"As-Burned" Cost	$/Ton	Input																					☒
10	Total Cost	Million $	(6) x (9)																					

Sulfur Content

11	Sulfur Content	Weight %	Input																					☒
12	Total Sulfur	10^3 long tons	(6) x (11) x 8.93																					

* Numbers in parentheses refer to line number of form.

Notes: ____________________

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Analysis Identification________

Date Prepared________

Analyst________

FIGURE 7. FORM FC – COAL CONSUMPTION AND COST AND SULFUR CONTENT SUMMARY

Line No.	Item	Units	Entry Source*	Year →																				Total
				Oil Consumption																				
1	Energy Generated	10^9 kwhr	Form E, Line (3)																					
2	Heat Rate	10^3 Btu/kwhr	Input																					☒
3	Total Btu Required	10^{12} Btu	(1) x (2)																					
4	Btu/Gal Oil	10^3 Btu/gal	Input																					☒
5	Gal Oil Consumed	10^6 gal	[(3) ÷ (4)] x 10^3																					☒
6	Barrels Oil Consumed	10^6 bbl	(5) ÷ 42.0																					
				Oil Cost																				
				If cost in ¢/million Btu																				
7	"As-Burned" Cost	¢/million Btu	Input																					☒
8	Total Cost	Million $	(3) x (7) x 10^{-2}																					
				If cost in $/barrel																				
9	"As-Burned" Cost	$/bbl	Input																					☒
10	Total Cost	Million $	(6) x (9)																					
				Sulfur Content																				
11	Sulfur Content	Weight %	Input																					☒
12	Btu/Lb Oil	10^3 Btu/lb	Input																					☒
13	Weight of Oil Consumed	10^6 long tons	[(3) ÷ (12)] x 0.4464																					
14	Total Sulfur	10^3 long tons	(11) x (13) x 10																					

* Numbers in parentheses refer to line number of form.

Notes: ____________________

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____

Analysis Identification ____________

Date Prepared ____________

Analyst ____________

FIGURE 8. FORM FO - OIL CONSUMPTION AND COST AND SULFUR CONTENT SUMMARY

Year →

Gas Consumption

Line No.	Item	Units	Entry Source*																					Total
1	Energy Generated	10^9 kwhr	Form E, Line (3)																					
2	Heat Rate	10^3 Btu/kwhr	Input																					☒
3	Total Btu Required	10^{12} Btu	(1) x (2)																					
4	Btu/cu ft	Btu/cu ft	Input																					☒
5	Cu Ft Gas Consumed	10^9 cu ft	[(3) + (4)] x 10^3																					

Gas Cost

If cost in ¢ / million Btu

6	"As-Burned" Cost	¢ / million Btu	Input																					☒
7	Total Cost	Million $	(3) x (6) x 10^{-2}																					

If cost in ¢ / thousand cu ft

8	"As-Burned" Cost	¢ / 10^3 cu ft	Input																					☒
9	Total Cost	Million $	(5) x (8) x 10^{-2}																					

* Numbers in parentheses refer to line number of form.

Notes: ____________________

Analysis Identification ________

Date Prepared ________

Analyst ________

FIGURE 9. FORM FG – GAS CONSUMPTION AND COST

the method of pricing according to whether the coal is used directly or from stockpiles, and this might result in reported as-burned costs being lower than fob plant costs [see Reference (4)]. As-burned cost data should be used wherever possible, but if not available, fob plant costs can be used. The analyst should note such cases on Forms FC, FO, or FG.

If the cost of coal at the mine mouth is known, then transportation charges must be added to obtain the fob plant cost. The following expression is used to compute the cost per ton of coal for the i^{th} year:

$$T_{F,i} = T_{M,i} + DT_{T,i} \quad . \tag{7}$$

A similar equation would be used to calculate oil costs. The terms of the above equation are defined as follows:

Symbol	Definition
T_F	Fob plant cost per ton of coal, \$/ton
T_M	Cost of coal at mine, \$/ton
D	Distance from mine to power plant, miles
T_T	Transportation charge, \$/ton-mile*

The value of T_F when adjusted to become an as-burned cost would then become the value for C in Equation (5).

The importance of fuel costs makes it desirable to carefully consider the impact an SO_2-control process will have in terms of the amount of fuel that will be consumed to produce the same amount of energy. An SO_2-control process can conceivably affect the heat rate or lead to greater electrical energy consumption within the plant. When these cases are identified, suitable allowance should be made in fuel consumption by altering the heat rate; or, in the case of increased electrical energy consumption, the amount of power delivered to the transmission point should be decreased, the result being an increase in the cost of energy for distribution. The electrical-energy requirements for the SO_2-control-process equipment and the by-product plant are allowed for in the calculation of net energy available for distribution (page 20).

Data regarding fuel costs are given in the section on Fuel Costs and Heating Value.

Fuel Changes. If more than one fuel is burned, then it is necessary to complete more than one form for fuel consumption, cost, and sulfur-content determination. The most direct way to accomplish this is to apportion the capacity-factor entry on Form E according to the percent of time that each different fuel is burned. The appropriate number of Forms FC, FO, or FG are then completed to determine the apportioned fuel cost and sulfur content. Each of these separate results for costs would then be combined to give the total annual fuel costs entered on Form R. The separate sulfur contents must then be combined to obtain the total sulfur, but no special form is provided for this – an appropriate note on the fuel-consumption forms used should call attention to the need for this calculation and its location on an attachment provided by the analyst.

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*These charges are sometimes expressed in mills/ton-mile.

Recurring Costs

Aside from annual fuel costs, the other recurring costs of interest are the operations and maintenance costs for the power plant and associated SO_2-control-process equipment, the transmission facilities, and the by-product plant. In addition, the annual taxes (nonincome) and insurance should be included in these costs. Also, annual credits should be allowed for the sale of by-product.

The expression used to assess total recurring costs ($T_{R,i}$) for the i^{th} year is

$$T_{R,i} = F_i + \sum_{n=1}^{4} (O_i + M_i + T_i + I_i)_n - C_i \quad . \tag{8}$$

The terms of this equation are defined as follows:

Symbol	Definition
F	Fuel cost
O	Operations cost
M	Maintenance cost
T	Taxes (nonincome)
I	Insurance cost
n	Subscript applies as follows: n = 1, power plant n = 2, transmission facilities n = 3, SO_2-control-process equipment n = 4, by-product plant
C	Income from sale by by-product

Form R, Recurring Cost Summary (Figure 10) is provided for organizing input data and performing the required cost calculations.

Fuel costs are entered from Form F, Fuel Consumption, Cost and Sulfur Content Summary. The other entries are obtained from the data discussed in the report section on cost elements.

The analyst has a number of options in the use of the form. Several of these are as follows:

(1) If annual costs are not varied throughout the planning period, then an entry is required only for the first year of operations and the total which is obtained by multiplying by the number of years in the planning period.

Line No.	Item	Entry Source*	Year →																				Total
			Annual Recurring Cost, millions of dollars																				
			Fuel																				
1	Fuel	Form FC, FO, or FG																					
			Power Plant																				
2	Operations**	Input																					
3	Maintenance**	Input																					
4	Annual Taxes (nonincome)	Input																					
5	Annual Insurance	Input																					
6	Subtotal	(2) + (3) + (4) + (5)																					
			Transmission Facilities																				
7	Operations**	Input																					
8	Maintenance**	Input																					
9	Annual Taxes (nonincome)	Input																					
10	Annual Insurance	Input																					
11	Subtotal	(7) + (8) + (9) + (10)																					
			Net – SO_2-Control-Process Equipment, By-Product Plant and Income																				
12	Net – SO_2 Control, etc.	(27) – from p. 2, Form R																					
			Net – Annual Recurring Costs																				
13	Net	(1) + (6) + (11) + (12)																					

*Numbers in parentheses refer to line number of form.

**If operations and maintenance not costed separately, enter on "Operations", lines (2) and (7).

Notes: ______________________________

Analysis Identification________

Date Prepared________

Analyst________

FIGURE 10. FORM R (p. 1 of 2) – RECURRING COST SUMMARY

Year →

Annual Recurring Cost, millions of dollars

SO$_2$-Control-Process Equipment***

Line No.	Item	Entry Source*																					
14	Operations**	Input																					
15	Maintenance**	Input																					
16	Annual Taxes (nonincome)	Input																					
17	Annual Insurance	Input																					
18	Subtotal	(14) + (15) + (16) + (17)																					

By-Product Plant

19	Operations**	Input																					
20	Maintenance**	Input																					
21	Annual Taxes (nonincome)	Input																					
22	Annual Insurance	Input																					
23	Subtotal	(19) + (20) + (21) + (22)																					

Income From By-Product Sales

24	Production, 1000 long tons	Input																					
25	Sales Price $/long ton	Input																					☒
26	Income, million $	(24) x (25) x 10^{-3}																					

Net

27	Net – SO$_2$ Control, etc.	(18) + (23) - (26)																					

* Numbers in parentheses refer to line number of form.

** If operations and maintenance not costed separately, enter on "Operations", lines (2) and (7).

*** If SO$_2$-control-process equipment and by-product plant not costed separately, enter on lines (14) through (18).

Notes: ________________________

Analysis Identification________

Date Prepared________

Analyst________

FIGURE 10 (CONTINUED). FORM R (p. 2 of 2) – RECURRING COST SUMMARY

(2) If the recurring costs for the SO_2-control-process equipment and by-product plant are not being analyzed separately, then entries are made in the process-equipment section only.

(3) If desired, the components of the SO_2-control process and/or by-product-plant recurring costs can be ignored and only the total entered, this being done when the analyst's interest is only the determination of the effects of incremental increases in costs.

(4) Form R allows for a 20-year planning period, but the period of interest can be varied according to the requirements of the analysis.

Some of the reasons for allowing for possible annual variations in recurring costs have been discussed previously. In addition, note that in the calculation of annual income from by-product sales, it is possible to vary the sales price realized if the analyst wants to evaluate the implications of, say, future price decreases.

Results of the Analysis

With the data generated by the completion of the previously discussed forms, it is possible to obtain the results of the analysis. Form S, Summary of Results of Analysis (Figure 11), is used for this purpose. This form provides for the entry of results for the power plant without SO_2 control and for the SO_2-control options considered. The appropriate options are noted by the analyst at the top of the unlabelled columns (see Form S). Depending upon the specific problem under consideration, the analyst would be interested in determining the nonrecurring and recurring costs for the power plant for one or more of the following cases:

(1) Without SO_2-control measures

(2) With various SO_2-control-process equipment and by-product plants

(3) Using low-sulfur fuels

(4) Remotely sited.

Analysis of the first case would be performed in all analyses, since this provides the basis for cost comparisons. The evaluation of more than one type of SO_2-control-process equipment and by-product plant may be of interest.

Provision is made on Form S for the calculation of the cost per unit nameplate power-generating capacity in terms of dollars per kilowatt. The entries on Form S are direct in meaning, and the terms used are as defined in the previous discussion of the forms referenced in the column, Data Source. Note that each line entry on Form S has the source of data indicated according to the form on which it is located. The Data Source column also shows the required arithmetic operations. The percentage value that is used to obtain the entry on Line 5 of Form S is discussed in the following section.

Form S also provides for the tabulation of data regarding sulfur removal. Although this model is not concerned with determining the efficiencies and the resultant

Line No.	Item	Units	Entry Source*	Without SO_2 Control	←SO_2-Control Options Considered→			
1	Total Nonrecurring Cost	Million \$	Form NR					
2	Nameplate Generating Capacity	Megawatts	Form A					
3	Dollars/Kw	\$/Kw	$[(1)/(2)] \times 10^3$					
4	Total Recurring Costs**	Million \$	Form R					
5	Total Annualized Nonrecurring Costs**	Million \$	(1) x (%) x 0.2					
6	Total Cost	Million \$	(4) + (5)					
7	Total Energy for Distribution	10^9 kwhr	Form E					
8	Cost/Energy	Mills/kwhr	(6) ÷ (7)					
9	Incremental Cost for SO_2 Control	Mills/kwhr	(8)***					
10	Total Sulfur Content of Fuel	10^3 long tons	Forms FC or FO					
11	Total Sulfur Removed	10^3 long tons	Process Analysis					
12	Net Cost/Ton of Sulfur Removed	\$/long ton	See Instructions					

*Numbers in parentheses refer to line number of form.

**Show percent of nonrecurring cost used for annualization ______.

***Subtract line (8) value in "Without SO_2 Control" column from appropriate column.

Notes: ________________________________

Analysis Identification ____________
Date Prepared ____________
Analyst ____________

FIGURE 11. FORM S – SUMMARY OF RESULTS OF ANALYSIS

amount of sulfur removed by various SO_2-control processes, the analyst would presumably generate such data on the basis of the characteristics of the control process under consideration and the amount of sulfur in the fuel. After determining the amount of sulfur removed during the planning period and the cost differences between the plant with and without SO_2 control, the incremental cost for sulfur removal could be determined in terms of mills/kwhr. These values for the different SO_2-control approaches of interest are obtained by subtracting the costs shown on Line 8 of Form S for the power plant without SO_2 control from the corresponding values for the SO_2-control options considered, and the result is entered on Line 9.

The incremental cost per ton of sulfur removed is also of interest. This value is obtained by taking the total of the recurring and annualized nonrecurring costs (Line 6, Form S) for the SO_2-control option case of interest and subtracting the same total for the power plant without SO_2 control. The cost differences obtained are divided by the total sulfur removed by the process. The result is then entered on Line 12 of Form S.

Note that the above discussion has been in terms of the totals for the entire planning period. However, if there is no significant annual variation in any of the values of interest, the analyst has the option of working with the values for the first year only. This approach will provide the same values for mills/kwhr and $/ton of sulfur.

Annualized Nonrecurring Costs. In order to obtain a value of mills/kwhr that reflects both nonrecurring and recurring costs, it is necessary to "annualize" the nonrecurring cost for the planning period. By doing this, it is possible to obtain a mills/kwhr value that provides a single number for the analyst to consider. However, the analyst should not forget the importance of the separate nonrecurring cost, since this provides important information regarding the initial investment required.

The annualization of nonrecurring costs is based upon application of a percentage value that includes consideration of financial costs, depreciation, and income-related taxes. These costs are discussed in the section on Carrying Charges - Treatment of Financial Costs, Depreciation, and Taxes. Table 21 in that section provides a tabulation of annual carrying charges that would be used to annualize the nonrecurring costs. For example, if the "rate of return" is assumed to be 7 percent and the depreciation period is 20 years, then the U.S. average value used would be 13.46 percent.

Graphic Presentation of Results. Aside from the tabulation of results found in Form S, graphic presentations are of interest. Plots of cumulative costs such as those shown in Figure 1 can be generated from the nonrecurring and recurring cost data. In addition, on the basis of the total sulfur content of the fuel and the efficiency of the SO_2-control process, it would be possible to generate curves showing the cumulative total of SO_2 released to the atmosphere with and without SO_2-control processes. Figure 12 shows such a plot for the case where two different SO_2-control processes are operated at the same efficiency. If the costs shown in Figure 1 apply, then Process A would be more attractive than Process B from a cost standpoint.

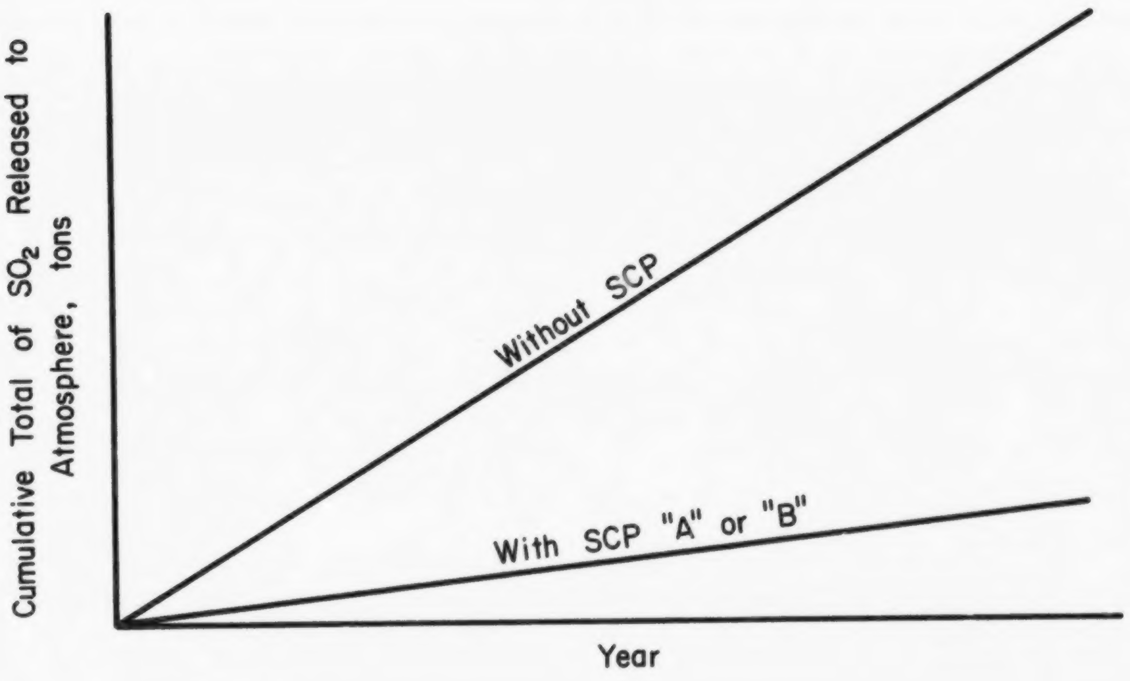


FIGURE 12. TOTAL SO_2 RELEASED TO ATMOSPHERE WITH AND WITHOUT SO_2-CONTROL PROCESSES (SCP)

Subsystem and Component Costs

The cost elements previously discussed have been primarily concerned with aggregate costs at the systems level. Exceptions have been made on Form NR, Plant Construction and Start-Up Costs, and Form T, Transmission Facilities Construction Costs, and this has been done only because of the convenience of showing alternative subsystem cost computations on the same form. To the extent possible the analyst should work with system-level costs in order to avoid the time-consuming effort to do detailed costing; however, cases may arise where it is in order to examine subsystem or component costs. For example, the incorporation of the SO_2-control process may require modifications of power-plant equipment. If these are extensive, then the impact on subsystem or component costs for the power plant may require evaluation.

The subsystems of the power plant are listed on the previously mentioned Form NR. Components of these subsystems are listed in the FPC publication, Uniform System of Accounts Prescribed for Public Utilities and Licenses.(2) For example, on page 45 of Reference (2), the components of the boiler-plant subsystem are listed as follows:

(1) Ash-handling equipment
(2) Boiler feed system
(3) Boiler-plant cranes and hoists
(4) Boilers and equipment
(5) Breeching and accessories
(6) Coal-handling and -storage equipment
(7) Draft equipment

(8) Gas-burning equipment
(9) Instruments and devices
(10) Lighting systems
(11) Oil-burning equipment
(12) Pulverized fuel equipment
(13) Stacks
(14) Station piping
(15) Stoker or equivalent feeding equipment
(16) Ventilating equipment
(17) Water purification equipment
(18) Water-supply systems
(19) Wood fuel equipment.

Reference (2) also provides a description of what is included in the above-listed equipment.

It is also possible to develop operations and maintenance expenses on the basis of more detailed component costs. For the electric plant, Reference (2) breaks down these costs as follows:

Operation	FPC Account No.
Operation supervision and engineering	500
Steam expenses	502
Steam from other sources	503
Steam transferred (credit)	504
Electric expenses	505
Miscellaneous steam power expenses	506
Rents	507
Maintenance	
Supervision and engineering	510
Structures	511
Boiler plant	512
Electric plant	513
Miscellaneous steam plant	514

A more detailed description of these cost elements is found in Reference (2), and detailed data regarding these costs are found in the annual FPC publication, Steam-Electric Plant Construction Cost and Annual Production Expenses.(3)

Note that fuel costs (FPC Account No. 501) has been omitted from the above list since this important expense is treated separately.

COST ELEMENTS FOR FOSSIL-FUEL-BURNING POWER PLANTS

The data for the calculation of costs are partially in the literature and partially unavailable, and quality varies from very accurate accountant reports to educated guesses. For the electrical system there is a large body of previous cost data which has been used for preparing cost-estimating relationships. For the sulfur control devices, only a few speculative estimates of costs are available. These estimates were then developed into cost-estimating relationships by the use of Lang factors and exponential functions.

The cost data for the electrical generating plants are published annually by the Federal Power Commission (FPC) in sufficient detail for the purpose of evaluating possible utility-rate impacts through the model and for obtaining cost-estimating relationships for estimating costs of new plants and fuel, operating, and maintenance expenses. The Bureau of Mines publishes extensive data on fuels. The FPC has published data on transmission-line costs. The cost data for the sulfur-control devices are the least accurate because no operating experience is available. Katell's estimates have generally been used for purposes related to the use of the model.

Cost-estimating relationships have been developed to represent the capital cost, the annualized costs, and the operating costs. In this report, capital costs are called nonrecurring costs and operating costs, recurring costs.

Initial Plant Costs

The initial plant cost includes the costs associated with the construction of a generating plant up to the time it is generating power. Since this model will be used with unfinished plants or proposed plants, a method is needed for estimating the initial cost. The cost of the plant depends upon the geographical location of the plant and upon the fuel to be burned. Coal-fired plants are more expensive than oil- or gas-fired plants because of the coal-handling equipment needed. Coal-fired plants can be converted to oil or gas firing with minimal additional cost, and the cost of a change from oil to gas or vice versa is also minimal. The initial cost of the plant is the major part of the capital investment and therefore the accuracy of this estimate will have a significant but lesser percentage effect on the accuracy of the final costs. Interest charges and amortization of the plant cost usually account for about 50 percent of the overall cost of electricity at the generating station.

The construction costs of steam-electric plants is published annually by the Federal Power Commission (FPC).(3) Unfortunately, the costs are presented for all units in a station rather than for the individual units. Although the cost of an individual unit could be determined by comparing the station cost of the year previous to startup of a new unit with the cost of current year, for the present purpose it appears adequate to consider only the costs of new stations. The costs of large, new, coal-fired generating stations which started operation between 1960 and 1965 are plotted in Figure 13. Cost data before 1960 cannot be related to these costs because of changes in technology and inflation.

It has been suggested that oil- and gas-fired units are only 80 percent of the cost of a coal-fired unit of the same capacity.(5) Regional cost variation can partially be

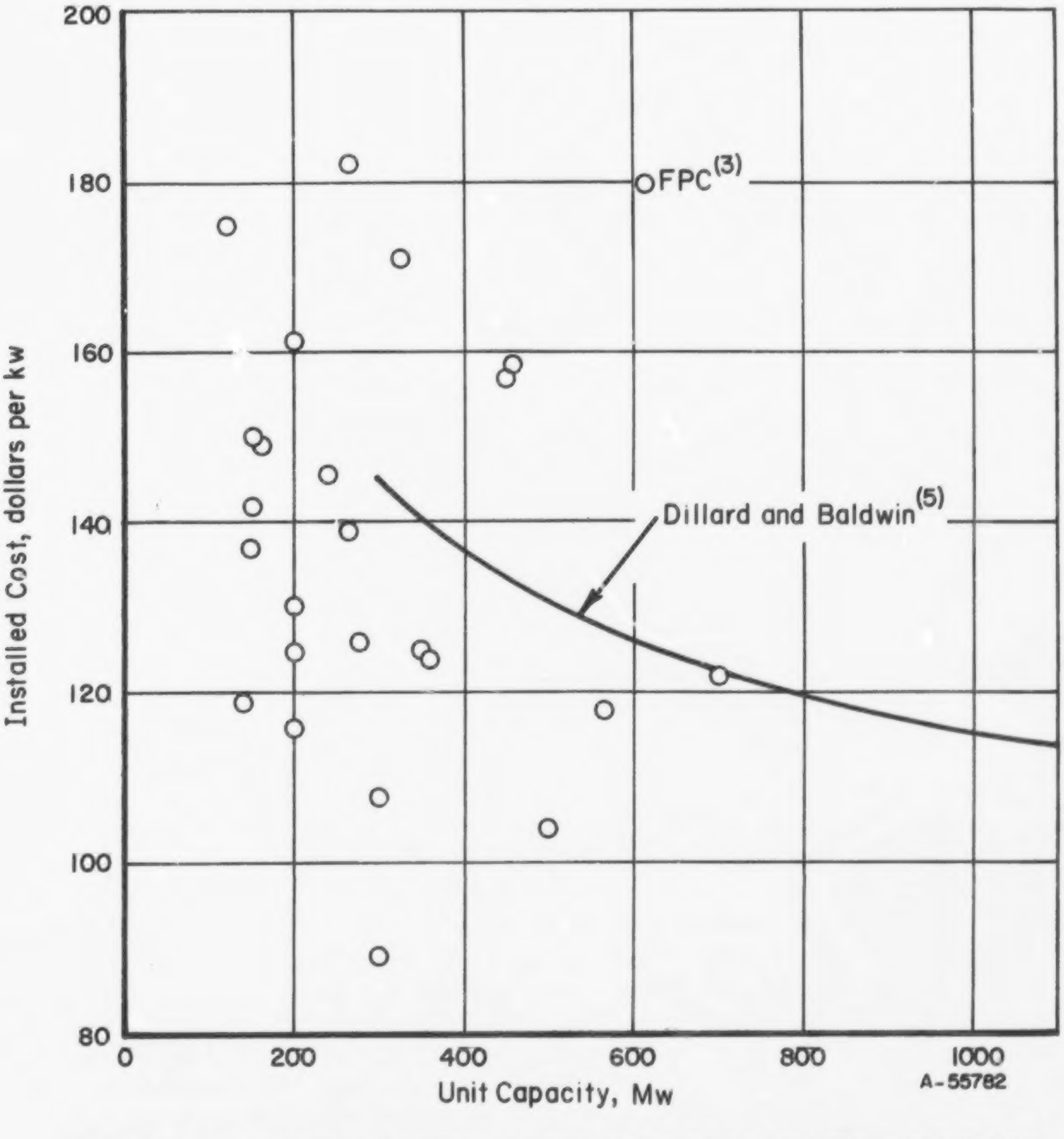


FIGURE 13. CONSTRUCTION COSTS FOR COAL-FIRED ELECTRIC GENERATING UNITS

determined from the construction-cost index(6) which is published quarterly and presents relative construction costs in major cities. Table 3 is a listing of recent cost indexes.

TABLE 3. CONSTRUCTION COST INDEXES FOR MAJOR CITIES (SEPTEMBER 1968)(6)

City	Index
Atlanta	919
Baltimore	974
Birmingham	901
Boston	1171
Chicago	1331
Cincinnati	1245
Cleveland	1460
Dallas	893
Denver	1054
Detroit	1389
Kansas City	1115
Los Angeles	1272
Minneapolis	1199
New Orleans	931
New York	1575
Philadelphia	1106
Pittsburgh	1169
St. Louis	1339
San Francisco	1413
Seattle	1255
Montreal	1047
Toronto	1031
U. S. Average	1186

Costs regionally corrected to a cost index of 1200 and the cost of oil- and gas-fired units increased by 25 percent (1/0.8) are plotted in Figure 14. The scatter in these costs is only somewhat less than the scatter in costs shown in Figure 13.

With a few exceptions, the construction costs of units larger than 300 Mw fall within 25 percent of the line shown in Figure 14. Since bid prices often vary by this amount, the correlation is probably as good as might be expected. The Eddystone plant, plotted at a cost of $240/kw, was a plant of a radical new design where an exceptionally low heat rate was obtained at the expense of high capital cost. Other variations are caused partially by some tradeoff in heat rate against capital costs and by some randomness.

The regional correction appears to be quite good. However, the costs are for metropolitan areas, and the costs for nonurban areas are not available. The cities listed in the cost index are scattered, and often it is difficult to decide which cost index to use. It is suggested that the cost index for the nearest city be used.

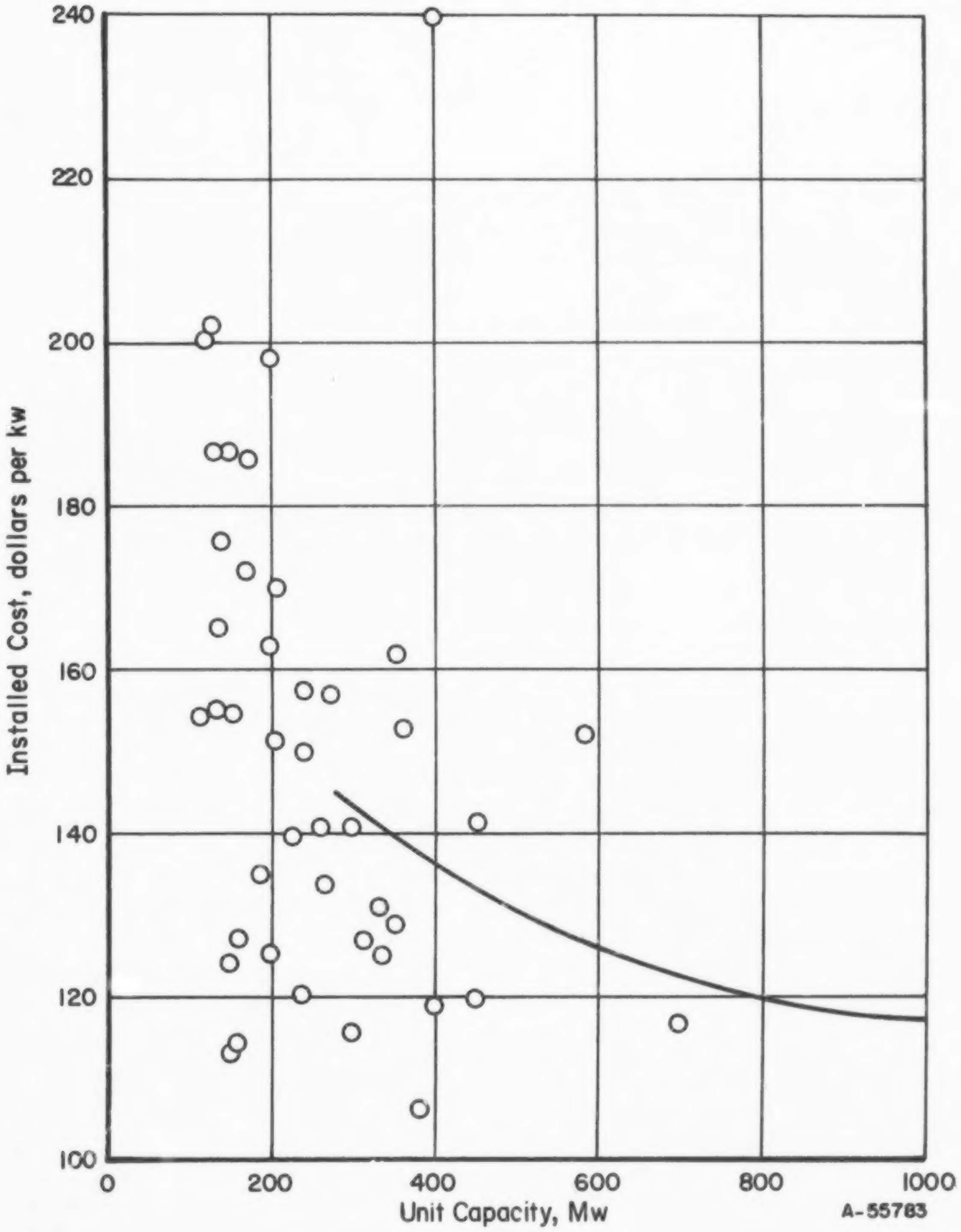


FIGURE 14. UNIT COSTS OF FOSSIL-FUELED ELECTRIC GENERATING STATIONS CORRECTED FOR REGIONAL VARIATION (ENR = 1200)

The difference in cost between gas- or oil-fired plants and a coal-fired plant is based on the additional cost of coal-handling equipment. The difference in costs is apparent when plant costs are examined. Oil-fired plants are sometimes considered to cost a few percent more than gas-fired plants, probably because of the storage facilities required for oil. This difference in cost is minimal, however, and should be ignored in using these values in the model.

Recommended Values

It is recommended that the cost of a plant be estimated using the Engineering Cost Index of the nearest city in conjunction with the curve shown in Figure 14, i.e., multiply the appropriate value read from the curve by the ratio of the cost index (value from Table 3, or a more current value) to 1200, the normalizing value. If the unit will not need coal-handling facilities, because oil or gas will be the fuel, this predicted cost should be modified by multiplying it by 0.8.

Operation and Maintenance

The operation and maintenance expenses are usually separated from the fuel cost, and this procedure is followed in the model. Operation and maintenance expenses amount to about 10 percent of the cost of electricity at the generating station; hence, sensitivity of results to these values is less than that to fuel costs and capital costs which represent a higher percentage of total generation cost.

Operation and maintenance costs are published annually by the Federal Power Commission(3) for most large power plants. These costs are plotted against the initial cost of the generating station in Figure 15.

Operation and maintenance costs for a station normally are expressed in mills/kwhr. A good correlation is observed in Figure 15, where operation and maintenance costs for new plants are plotted as a function of the initial cost of the plant. Changes in operation and maintenance costs are seen to be associated fairly well with changes in the $/kw first cost of the unit. This is a result of two relationships. A given generating unit which is double the size of another will not require twice the operating and maintenance personnel. The larger unit will have the same number of boilers, turbines, and generators as the smaller one and is likely to have a similar number of burners, pumps, and controls. Only the size of each will be larger. Thus, while more labor will be involved in repairing a larger pump, it should not be double. The second relationship is that as generating-unit sizes double, their first costs usually do not. Therefore, it would be expected that the operating and maintenance expenses for a unit expressed in mills/kwhr would decrease as a unit's installed cost in $/kw decreased, because it is probable that a larger unit is being investigated.

Operational costs are primarily labor costs, and regional variations in labor rates are reflected in the capital costs. Therefore, regional-cost corrections are inherent in the estimating method. The cost estimates are below the national average of 0.75 mill/kwhr since the newer plants need less maintenance because of advanced technology and operational costs are reduced because of large-scale operation.

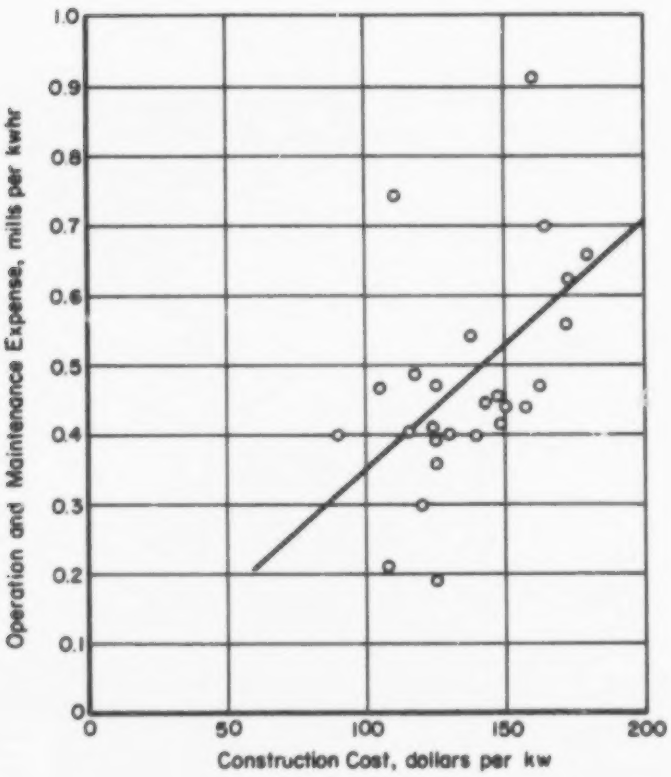


FIGURE 15. COST-ESTIMATING RELATIONSHIP FOR OPERATION AND MAINTENANCE COSTS

Recommended Procedure

It is recommended that the operation and maintenance cost be estimated from the correlating line on Figure 15.

Transmission Costs

The transmission line is used to transport the power from the generating station to the distribution area. In the context used in the model, the transmission plant denotes the difference in equipment required by alternatives between the generating station and the distribution area. If, under two alternatives, the generating station is within the distribution area for both, it is assumed that no differences in transmission plant need be considered. Transmission plants may be ac or dc, and they may be overhead or underground. They are characterized by high capital costs and low operating costs, and their voltage is usually at least double that of the distribution system. Generally, the economic size of the transmission line is one-third to one-forth the maximum technical capability of the line. Therefore, a line will take rather severe overloads under emergency conditions. Frequently, roughly parallel lines are installed to increase system reliability. Direct-current transmission is in the experimental stage and apparently will be preferred only for transmitting very large blocks of power long distances, for use with underground systems or for transmitting energy through large bodies of water. Alternating-current lines are normally used. Underground transmission lines are used only in urban areas and are 10 to 15 times as expensive as overhead lines. Because of the higher voltages, electromagnetic field characteristics, and generally greater length of transmission lines, both underground and overhead facilities require reactors to compensate for the reactive impedance of the line and to prevent the energy from being dissipated before it reaches its destination.

Data

Table 4 presents the costs of overhead lines of various voltages. However, note that the power rating in the table is the technical rating and not the economic rating. Figure 16 presents the cost of transformers for increasing the voltage from 220 kv to a higher transmission voltage. Table 5 presents the costs of compensating reactors for the transmission lines. All of these values have been taken from a Federal Power Commission report. (7)

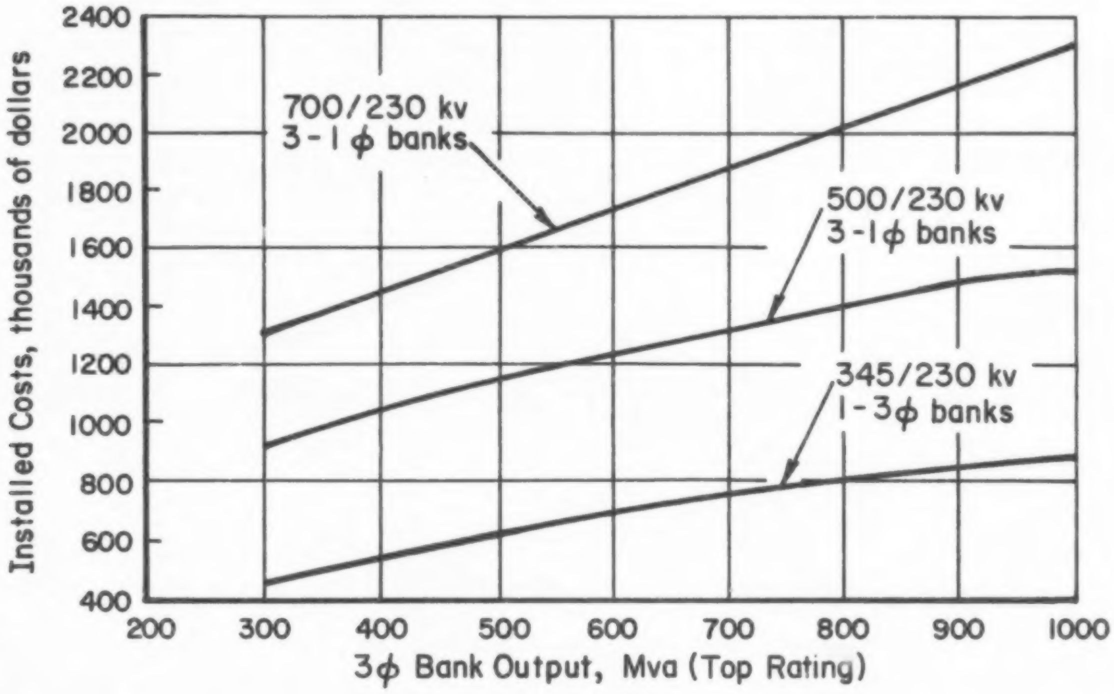


FIGURE 16. AUTO-TRANSFORMER COSTS (THREE WINDING, OA/FOA/FOA, 15-KV TERTIARY HV AND LV-GROUNDED Y)

Note: Transformer costs include foundations, steel, fire protection, arresters, labor, contingencies, other direct construction costs, engineering and general overheads (21%). These costs are typical only.

The Tennessee Valley Authority (TVA)(8) reported that 500 kv was the economic voltage in the power range from 1000 to 2000 Mw and 345 kv was optimum at 500 Mw. Guyker et al. (9) discussed the economic selection of conductors. From these discussions it appears that the selection of type of transmission line will not be extremely critical and a small error in voltage selection will only shift the costs between capital and operating costs rather than cause a major error in overall costs.

TABLE 4. RANGE OF ESTIMATED COSTS PER MILE FOR HIGH-VOLTAGE OVERHEAD TRANSMISSION LINES(7)

(Exclusive of Compensation, Conversion, Terminal, and Transformation Cost)

Oper. Volt., kv	ACSR Cond. Size, MCM	Nominal Summer Thermal Rating(a), Mva	No. of Circuits & Structure Material(b)	Reported Range of Material Cost/Mile(c), $1000	Reported Range of Labor Cost/Mile, $1000		Reported Range of Right-of-Way Cost(f), $1000/Mile	Total Cost/Mile, $1000	
					Foundations(d)	Tower Erection and Stringing(e)		Reported Range	Adjusted Average
					Alternating-Current Lines				
700	1-477	75	1-W	6.5-23.0	0-24.0	5.9-24.0	0-38.0	19.8-86.0	50.8
	1-795	105	1-W	9.4-23.5	0-26.0	7.7-30.0	0-38.0	23.4-100.0	50.9
	1-795	105	1-S	13.2-28.0	3.0-38.0	9.6-36.0	7.1-38.0	34.9-122.0	66.2
	1-795	210	2-S	22.7-36.0	5.0-48.0	16.9-60.6	7.1-38.0	51.3-170.0	87.8
138	1-477	150	1-W	8.9-25.0	0-26.0	7.3-20.0	7.5-46.0	35.2-94.1	65.4
	1-795	210	1-W	11.3-26.0	0-26.0	8.4-36.0	7.5-46.0	32.2-111.0	60.7
	1-795	210	1-S	14.4-30.0	3.6-42.0	11.4-42.0	7.5-46.0	36.9-136.0	73.0
	1-795	420	2-S	25.6-42.0	5.3-51.0	16.9-66.0	7.5-46.0	54.5-184.0	97.0
230	1-954	385	1-W	11.8-29.0	0-20.0	9.3-43.0	7.7-52.0	33.5-124.0	75.2
	1-1431	490	1-S	20.5-45.0	4.0-53.0	12.1-58.0	7.9-52.0	44.3-173.0	94.1
	1-1431	980	2-S	31.0-60.0	5.7-64.0	17.1-90.0	7.7-52.0	61.6-237.0	128.4
345	2-795	1050	1-W	25.0-36.5	0-20.0	14.4-54.0	11.6-57.0	63.9-147.0	91.8
	2-795	1050	1-S	24.5-56.0	4.2-38.0	15.6-57.0	8.0-57.0	52.5-171.0	101.7
	2-1590	3160	2-S	45.0-106.0	5.7-93.0	26.0-159.0	7.9-57.0	85.1-393.0	183.5
500	2-1780	2470	1-S	36.3-72.0	4.4-72.0	26.6-120.0	9.3-64.0	76.5-306.0	155.1
700	4-954	4700	1-S	78.0-93.6	5.6-84.0	41.8-168.0	15.9-76.0	164.5-387.0	199.4
					Direct-Current Lines				
±200	2-1590	600	1-S	31.6-43.0	5.7-26.0	21.0-54.0	10.4-33.8	71.9-151.0	94.8
±400	2-1590	1200	1-S	26.6-48.0	3.9-30.0	19.6-57.0	11.8-40.5	58.2-160.0	95.7
±600	2-1590	2160	1-S	43.2-62.6	5.9-34.0	27.7-60.0	13.0-47.5	94.0-176.0	129.0

Note: Engineering and overhead costs are included in the various items. Limits of ranges on individual items do not exactly equal the sum of the corresponding limits because of variations in breakdowns because of reporting companies.

(a) Based on 85 C conductor and 40 C ambient air temperature plus solar heating, 2.0 fps wind velocity, and 0.5 emmissivity coefficient. Terminal equipment based on 1500-ampere valve ratings for ±200 and ±400 kilovolts, and 1800 amperes for ±600 kilovolts.

(b) 1 = one circuit on single-circuit tower, 2 = two circuits on double-circuit tower, W = wood pole, S = steel tower.

(c) Includes structure, insulators, conductors, fittings, and all other materials including foundation material, sales tax, and storage or handling charges. Does not include transformer cost.

(d) Includes all foundation installation, surveying, grounding and any necessary construction roads.

(e) Includes all costs of assembling the material into a complete line.

(f) Includes property and clearing costs for 60 percent of right of way. R/W widths 69 kv-ac-75 ft.; 138 kv-ac-100 ft.; 230 kv-ac and ±200 kv-dc-125 ft.; 345 kv-ac and ±400 kv-dc-150 ft.; 500 kv-ac and ±600 kv-dc-175 ft.; 700 kv-ac-225 ft.

The maintenance cost was suggested as 1 percent of the capital cost in the report on Underground Power Transmission. (7) The electrical losses were estimated by calculating I^2R loss from estimated line sizes, assuming a power factor of one. Corona losses are negligible at transmission voltages below 500 kv, and at 500 kv they are important only at times of precipitation when they may be as high as 100 kw/mile. Corona losses have been discussed by Anderson et al.(10)

TABLE 5. COST OF COMPENSATING REACTORS

Reactance, MVAR	220-345 kv, $/KVAR	500 kv, $/KVAR
50	6	9
100	4	6
200	3	4
300	2.5	3

Discussion

From the three-to-one variation in cost for a line presented in Table 4, it can be seen that an accurate estimate of transmission-line costs cannot be obtained without details of the line. For the cost model it is suggested that an average cost be used where specific data are not available. The data plotted in Figure 17 indicate the wide variability in capital cost. It is also suggested that the line be designed for operation at about 30 percent of its thermal rating. This is roughly in line with TVA voltage recommendations for the various power capabilities. Also, calculations using the costs presented later indicate that this is approximately the economic loading. These calculations also indicated that the 30 percent figure was not critical.

The transformer costs will be inherent in the system for voltages up to about 220 kv because the main distribution system will probably operate at that voltage. Therefore, these costs should be included in distribution costs, which are not part of this study. Transformer cost for stepup and stepdown over that voltage should be added to the transmission costs. Shunt impedances for compensation have not been considered. They will not be needed for transmission distances less than 200 miles.

To assume reliable operations, it is suggested that the same number of transmission lines be used as the generating plant has generators. Usually a generator is sized so that its shutdown will not affect system reliability, and the transmission line should be sized on the same basis. Underground lines are very expensive and will probably be used only in the distribution system. The costs are from 10 to 15 times the cost of an overhead line. If underground lines are needed, it is suggested that the minimum figure of 10 times the cost of overhead lines be used.

The figure of 1 percent for maintenance cost in the FPC report(7) appears reasonable, and it is suggested that this number be used. This includes the maintenance of access roads, weed control, and occasional storm losses. The I^2R losses can be calculated easily after the wire size is estimated. The wire sizes in Table 4 were used for estimating this loss. However, the I^2R loss varies with the loading of the line. If the loading schedule is not known, it is suggested that the line be considered as operating at design load or completely disconnected from the station and load. Corona losses will depend upon the weather conditions. For the curves presented later, it is assumed that the corona losses will average 20 kw/mile for a 500-kv line and be negligible at lower voltages. Except at light loadings, this is not an important cost. A loss of 20 kw/mile assumes that precipitation, dew, frost, fog, or other corona-causing weather conditions will occur 20 percent of the time.

Recommended Procedure

The following steps constitute the recommended procedure for determining the costs associated with power transmission from generation locations outside the distribution network:

(1) Determine the capital cost of the transmission line from Figure 18

(2) Determine the capital cost (if any) of transformers from Figure 19

(3) Sum to determine capital cost

(4) Multiply the capital cost by 0.01 to determine annual maintenance cost

(5) Determine the electrical losses from Figure 20 and subtract this loss from the net power generated by the generating plant.

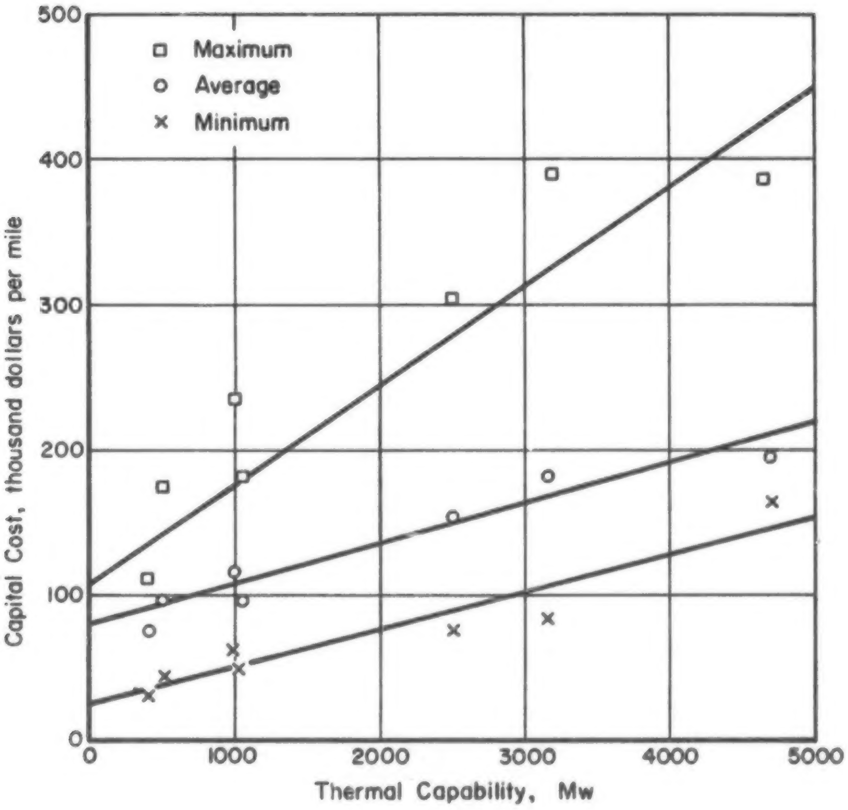


FIGURE 17. CAPITAL COST OF TRANSMISSION LINES

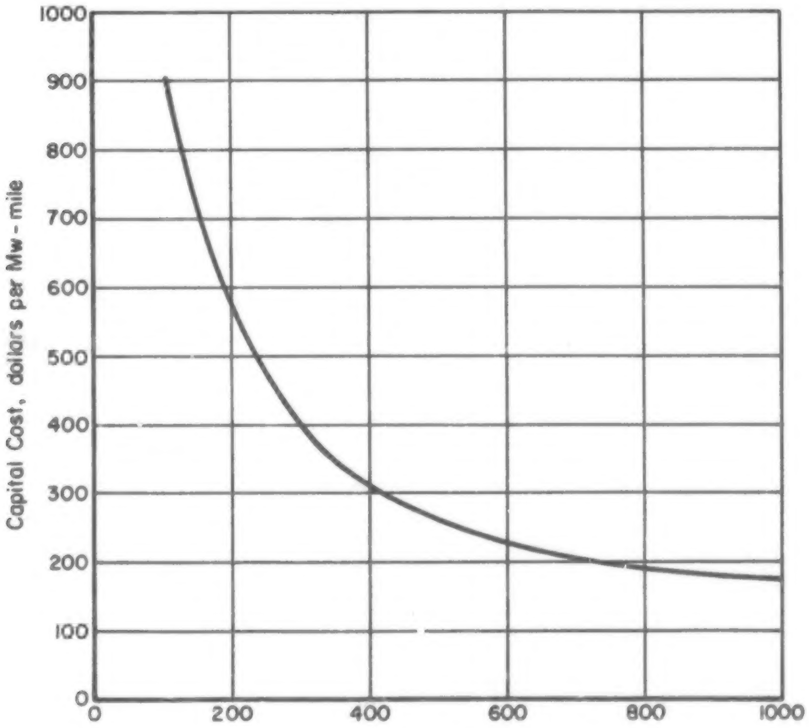


FIGURE 18. CAPITAL COSTS FOR OVERHEAD TRANSMISSION LINES

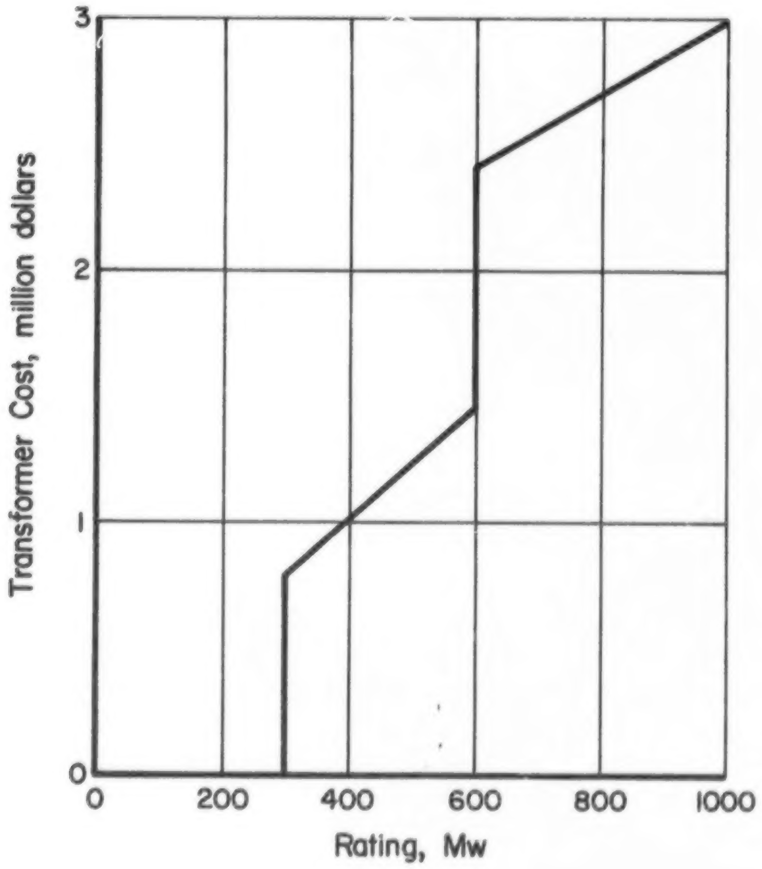


FIGURE 19. TRANSFORMER COSTS FOR TRANSMISSION LINES (STEPUP AND STEPDOWN FROM 220 kv)

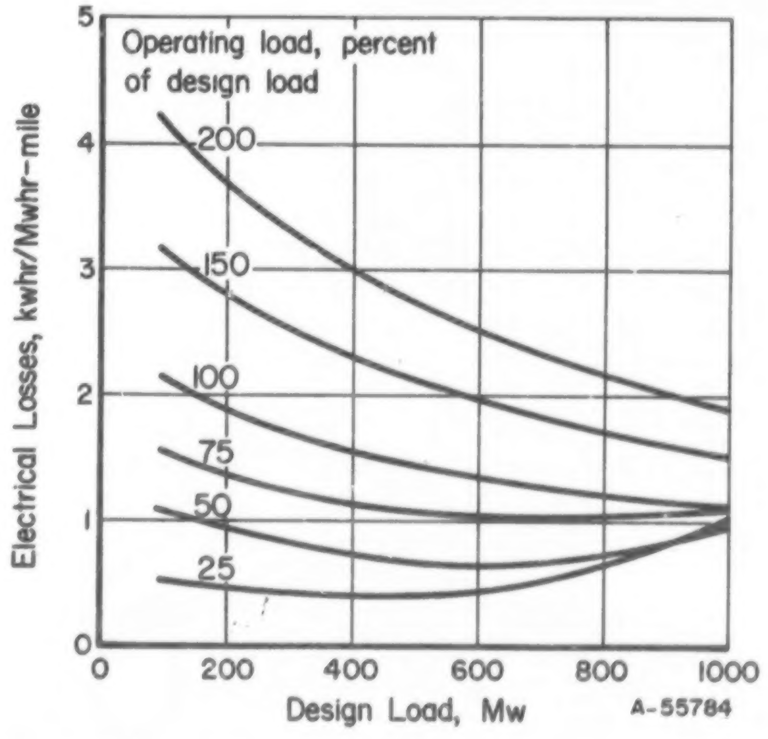


FIGURE 20. ELECTRICAL LOSSES IN TRANSMISSION LINES PER Mw-hr DELIVERED

Fuel Costs and Heating Value

Data on fuel costs are usually available only in some aggregated form as shown in Table 6. While this table is useful in identifying general regional trends, it overstates the cost of alternatives available to utilities currently planning a new, large facility. Average delivered coal prices are particularly misleading because they do not adequately reflect the volume economies available to a large purchaser who is located near the mine mouth, purchases from captive mines, or uses unit-train hauling. These differences are indicated by comparing data from Table 6 with those in Table 7 which shows typical fuel costs for utilities contacted during this program. As an example, while the average delivered coal price to all utilities in the East South Central Census Region in 1966 was 19.3¢/million Btu, the delivered cost to three of TVA's larger stations in the same area ranged from 13.7¢/million Btu (in a mine-mouth location) to 17.9¢/million Btu.

It would also be desirable to distinguish fuel costs at the source and the transportation component from the delivered price. An attempt was made to identify these components during utility interviews, and where adequate data were available, the cost of coal at the source was estimated (Table 7). The deviation in coal costs at the mine is seen to be much smaller for the three TVA stations mentioned before than it was for the delivered cost of fuel. It has been found that for a given mode of transportation and distance, the costs per ton mile are fairly uniform. These transportation costs can be applied to a particular evaluation considering alternative plant types and sites where fuel source and source costs are known. However, to develop a mass of data on estimated fuel cost at the mine would require, as an example, the listing of a large number of facilities and their as-burned fuel costs, determining the fuel-source location, and subtracting an estimated transportation charge from this.

At present, a reasonable data base may be developed by assuming that each utility performs a rigorous analysis of alternatives in selecting a plant site, and that their choice represents the optimum costs available to them at the time, including both coal costs as mined and transportation charges. Therefore, as-burned fuel costs have been tabulated from the FPC's publication Steam Electric Plant Construction Cost and Annual Production Expenses(3) for all generating stations 500 Mw(e) and larger. Volume transportation methods are usually employed and should be reflected in the fuel costs for these larger stations. These data have been plotted on United States maps and coal costs are presented in Figure 21, oil costs in Figure 22, and gas costs in Figure 23. Thus, in any evaluation of a general nature which does not require the isolation of the fuel transportation component, the delivered costs of alternative fuels may be estimated by referring to these three maps.

The heating value of coal is seen to vary considerably among different regions. Heating-value data were tabulated from the FPC's steam plant report(3) and are presented in Figure 24. The heat contents of oil and natural gas are more consistent and their average values are also shown in Figure 24.

Unfortunately, the heating values for oil are shown in terms of Btu's/gal, while to compute the sulfur content of oil used as fuel, a value in terms of Btu's/lb is needed. Values of typical heating values per pound for residual fuel oils are given by the American Petroleum Institute(12) as follows:

TABLE 6. STEAM ELECTRIC GENERATING STATIONS' AVERAGE "AS-BURNED" FUEL COSTS FOR 1966(4)

Region	Costs, cents/million Btu		
	Coal	Oil	Gas
New England	33.6	32.9	33.8
Middle Atlantic	26.5	31.8	34.4
E. N. Central	24.4	--	25.9
W. N. Central	26.4	--	24.2
South Atlantic	25.6	33.6	31.8
E. S. Central	19.3	--	22.7
W. S. Central	--	--	19.8
Mountain	20.4	25.4	26.7
Pacific	--	31.5	31.5
U. S. Average	29.7	32.4	25.0

TABLE 7. FUEL COSTS AND CHARACTERISTICS OF UTILITIES' GENERATING STATIONS OBTAINED THROUGH INTERVIEWS

Plant (Utility)	Net Size, Mine	Plant Location	Fuel	Fuel Cost FOB Mine, ¢/million Btu	Transp. Cost, ¢/million Btu (Dist., miles)	Delivered Fuel Cost, ¢/million Btu	Sulfur Content, percent
Pittsburgh[7] (P. G. &E)	735	Calif.	Oil			32.8	1.1 to 1.5
			Gas			31.2[b]	
			Coal			36-40(E)	
Joliet (Com. Ed.)	1,862	Joliet, Ill.	Coal	15.94(E)	6.12(300)[a]	22.06	
Waukegan (Com. Ed.)	1,093	Waukegan, Ill.	Coal	19.61(E)	7.46(200)	27.07	
(So. Cal. Ed.)		Los Angeles, Calif.	Oil			38.0	0.5 or less
			Oil			30.0	1.7
(P.S. of Okla.)		Tulsa, Okla.	Gas			19.0	
			Coal			20.5(E)	
(Pac. P.&L.)		Centralia, Wash.	Coal			16.0	0.7
(P.S. of Colo.)		Denver, Colo.	Coal	14.85(E)	8.65(180)	23.5	0.65
			Gas			22.5[b]	
Bull Run (TVA)			Coal	11.43	4.77(298)[a]	16.2	2.3
Gallatin (TVA)	1,255	Gallatin, Tenn.	Coal	13.23	4.67(119)	17.9	4.1
Paradise (TVA)	1,908	Drakesboro, Ky.	Coal	13.7	0	13.7	4.3
(Bost. Ed.)		Boston	Oil			25.0	2.8
(Cons. Ed.)		New York City	Oil			37.0-38.0	1.0 or less
			Oil			32.0-33.0[c]	2.5
			Coal			38.0	1.0 or less
			Coal			29.0	2.0
(P.S. of N.J.)			Coal	See Figure 25			
			Oil	See Table 9			

(E) Estimated.
(a) Unit train.
(b) Interruptible gas.
(c) For comparison only; all fuel burned under 1 percent sulfur.

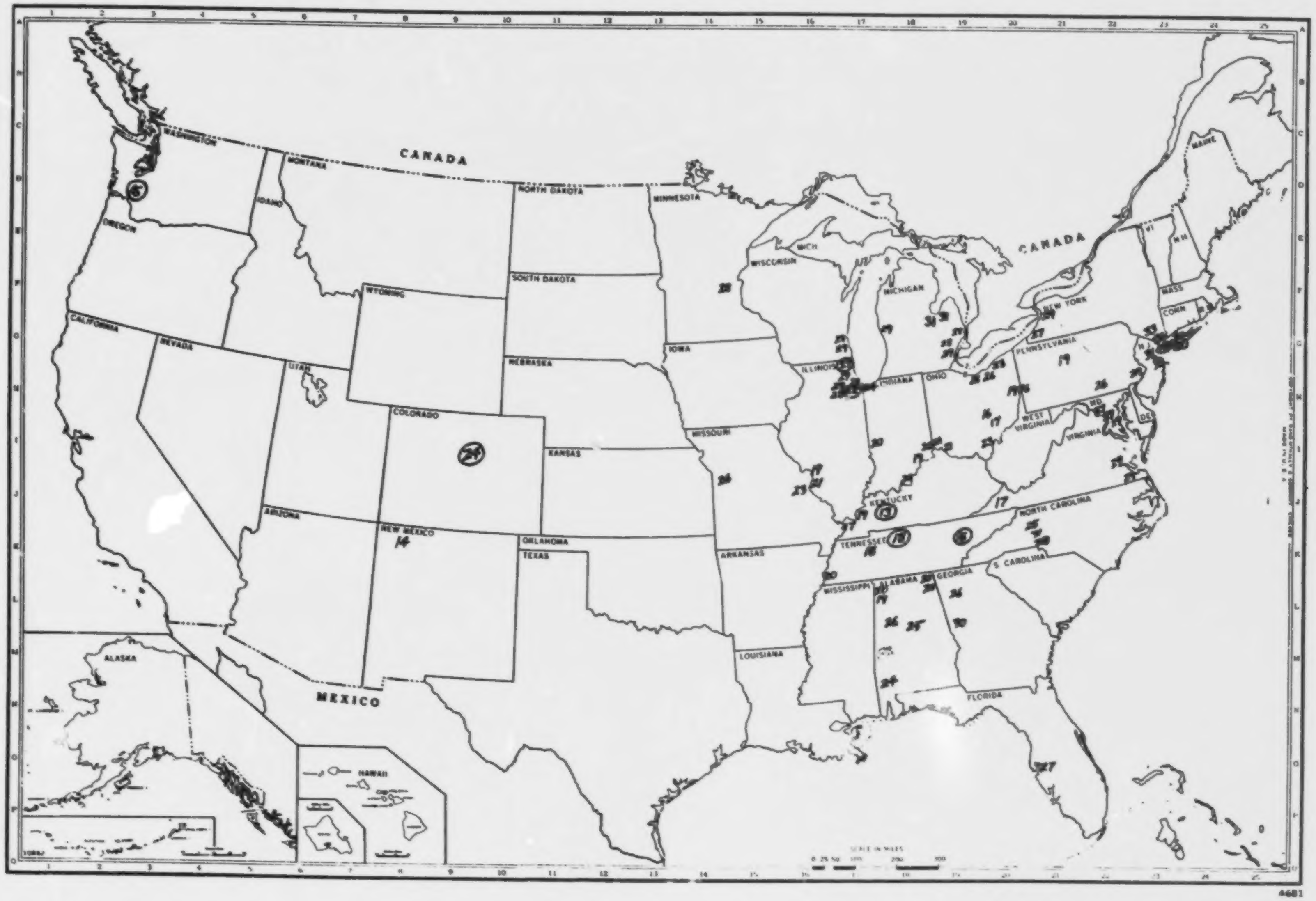


FIGURE 21. 1966 AVERAGE COST OF COAL "AS BURNED" AT ELECTRIC GENERATING STATIONS 500 Mwe AND LARGER IN CENTS PER MILLION Btu(3)

Note: Circled numbers were obtained through interview.

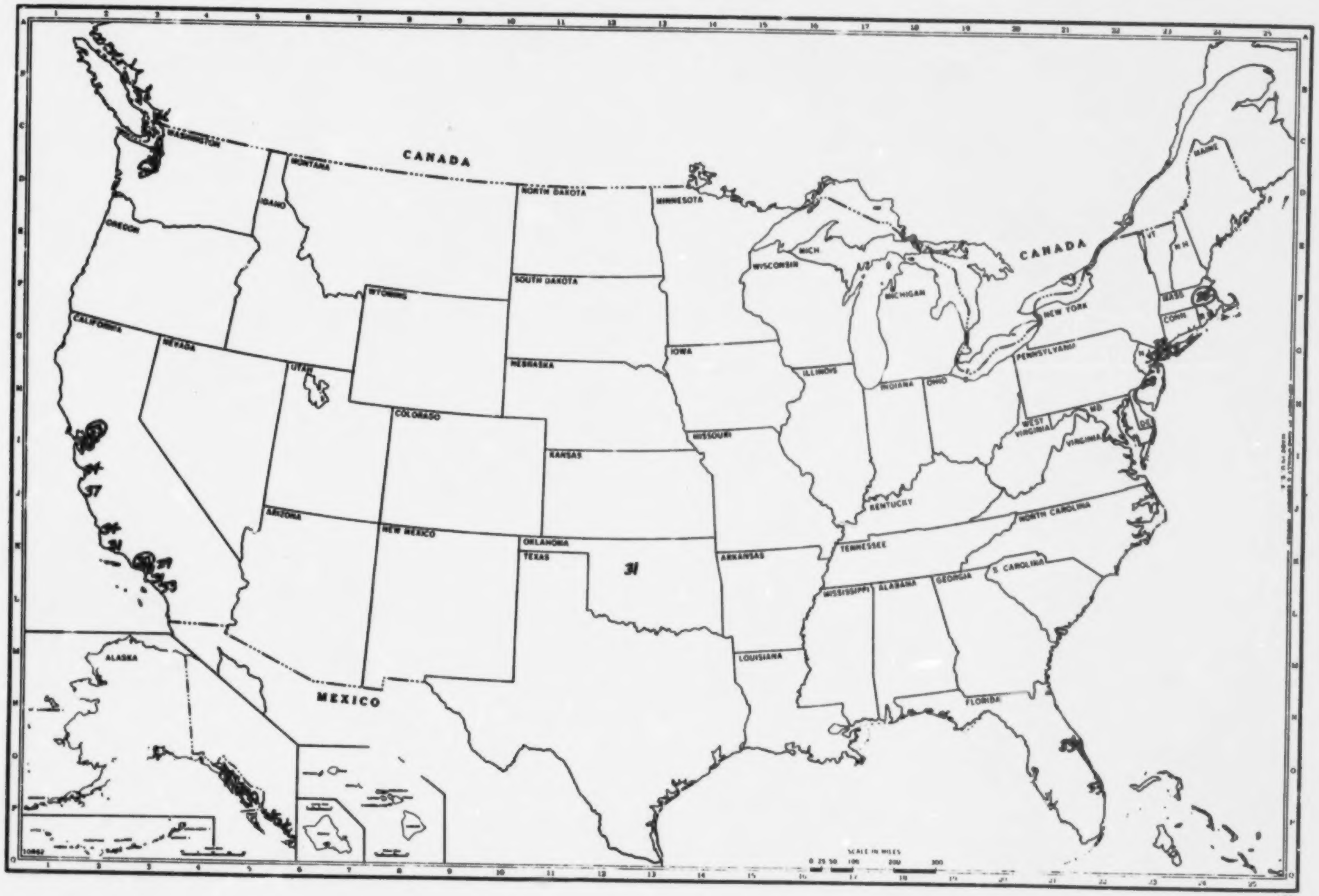


FIGURE 22. 1966 AVERAGE COST OF OIL "AS BURNED" AT ELECTRIC GENERATING STATIONS 500 Mwe AND LARGER IN CENTS PER MILLION Btu(3)

Note: Circled numbers were obtained through interview.

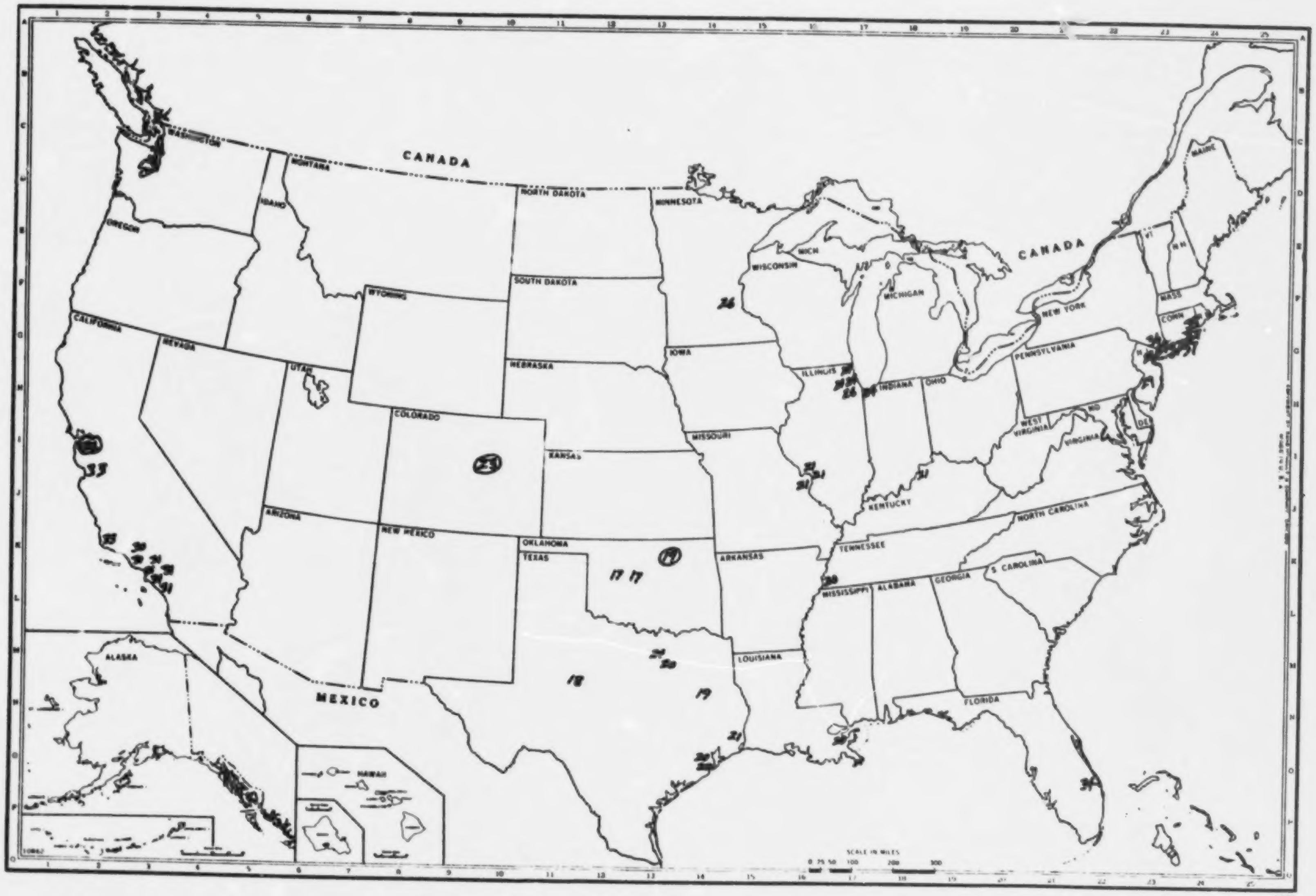
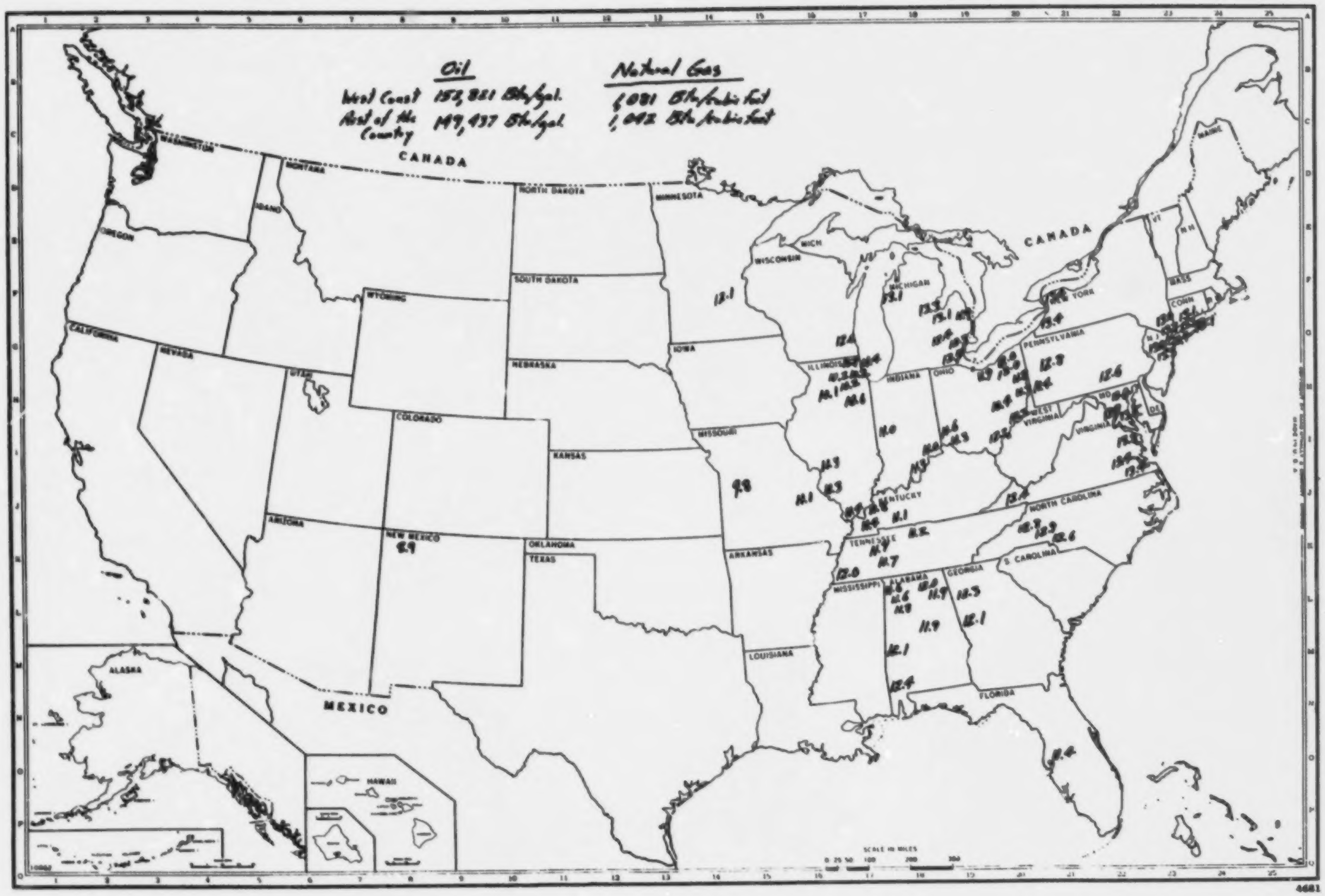


FIGURE 23. 1966 AVERAGE COST OF NATURAL GAS "AS BURNED" AT ELECTRIC GENERATING STATIONS 500 Mwe AND LARGER IN CENTS PER MILLION BTU

Note: Circled numbers were obtained through interview.



Oil

West Coast 153,881 Btu/gal.
Rest of the Country 149,437 Btu/gal.

Natural Gas

1,081 Btu/cubic foot
1,042 Btu/cubic foot

FIGURE 24. 1966 AVERAGE HEATING VALUE OF COAL BURNED AT ELECTRIC GENERATING STATIONS 500 Mwe AND LARGER IN 1000 BTU'S PER POUND

Note: Data for oil and gas were averaged but not plotted.

Residual Fuel Oils	Gravity, deg API at 60 F	Btu/Lb Liquid
California	16.5	18,319
Kentucky	15.2	18,651
California	7.6	17,970

Another approach is to use the chart given by Perry(13) to convert the values shown on Figure 24 (for oil) to Btu's/lb. This results in the following:

	Oil Heating Value	
	Btu/Gal	Btu/Lb
West Coast	152,821	18,860
Rest of the Country	149,437	19,080

It is further observed that the API typical values are not consistent with the Perry chart, which indicates that actual values for each case of interest would be desirable. (Note that a constant value of 18,700 Btu/lb has been used in the examples shown in a later section of this report.)

One method of reducing sulfur oxide emissions, which is always available to utilities, is to burn a fuel with a lower sulfur content.* For many locations, however, this alternative imposes substantial cost consequences. As an example, most of the United States' reserves of low sulfur coal are located west of the Mississippi River(11), whereas a majority of the country's electrical generation facilities are located near more densely populated urban centers east of the Mississippi. For most of the eastern plants, the transportation cost for moving low-sulfur coal from western mines would be prohibitive.

Some reserves of low-sulfur coal are located in the eastern coal fields. Unfortunately, the use of coal with more than 1 percent sulfur content has long imposed an undesirable cost consequence on the steel industry. Because a majority of steel plants are still located east of the Mississippi River, the steel industry has taken prior claim on a major portion of the eastern reserves of low-sulfur coal through long-term contracts. Most plains states and west-coast utilities seem able to obtain low-sulfur coal with little cost penalty.

East-coast utilities also face higher transportation charges for low-sulfur oil. Most oil that is competitively priced for utility use on the east coast is shipped from South America. However, Venezuelan oil, as an example, is typically high in sulfur content. The lowest cost low sulfur oil in many cases is shipped from Africa, and this results in a higher delivered cost. On the west coast, oil with 2 percent sulfur or less is available at competitive prices from domestic sources.

An example of these cost consequences is offered by the experience of Consolidated Edison, the electric utility serving New York City, which recently reduced the allowable sulfur content of their fuel purchases from 2.5 percent to 1 percent or less. Changes in volume fuel costs as a result of the new sulfur specifications are summarized in Table 8.

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*This can be achieved not only by using natural fuels which are low in sulfur but also by modifying the fuel. For example, currently there are efforts by the National Air Pollution Control Administration to develop and demonstrate improved conventional coal-cleaning practices for reducing sulfur contents.

TABLE 8. VOLUME FUEL COSTS AT THE GENERATING STATION FOR CONSOLIDATED EDISON CO. OF N. Y., INC. BEFORE AND AFTER ESTABLISHMENT OF POLICY TO BURN LOW-SULFUR FUEL

Fuel	Costs, ¢/million Btu Sulfur Content, percent 2.5	 1.0	Percent Increase
Oil - "Delivered"	32-33	37-38	15.4
Coal - "Delivered"	29	35(a)	20.7
Transp. component	10	17	--
Estimated price fob mine	19	18	--

(a) Price on August, 1969, was 37¢/MM Btu because of increased transportation charges.

In addition, this utility had been purchasing small volumes of coal with under 1 percent sulfur content for the same price as coal with 2 percent sulfur before their policy change. The cost of low-sulfur coal rose by $1.50 per ton when the quantity purchased from this source increased to 3.5 million tons per year. Another indication of the elasticity of the demand curve for a particular grade of fuel at a given time and location is the drop in the price of high-sulfur oil in New York City from the range 32 to 33¢/million Btu to 28¢/ million Btu after Consolidated Edison stopped purchasing 2.5 percent sulfur oil.

Further evidence of the impact of sulfur content of fuel upon its delivered price was obtained from Public Service Electric and Gas Company, a New Jersey utility that is currently faced with legislation proposing to limit the sulfur content of fuels they burn. In anticipation of this regulation, price quotations on alternative supplies were obtained, and these are shown for coal in Figure 25 and for oil in Table 9. It is seen in Figure 25 that the delivered cost of coals increased by 23 percent as their average sulfur contents were decreased from 2.7 to 0.8 percent. These examples reflect the impact of low-sulfur fuel on price at only two eastern utilities. It is anticipated that these prices would rise markedly again if additional utilities demand low-sulfur fuel.

Heat Rates

The amount of fuel burned to generate 1 kilowatt of electricity is determined from the heat rate of the generating unit. The heat rates of new plants has been decreasing gradually with time, and the best stations now are operating with a heat rate of about 8,700 Btu/kwhr. As better materials for the plants are developed, the heat rates will undoubtably continue their downward trend. Apparently, the heat rates can be improved by increasing the complexity and cost of a station. However, the complex design of a station may be justified only for the very large unit.

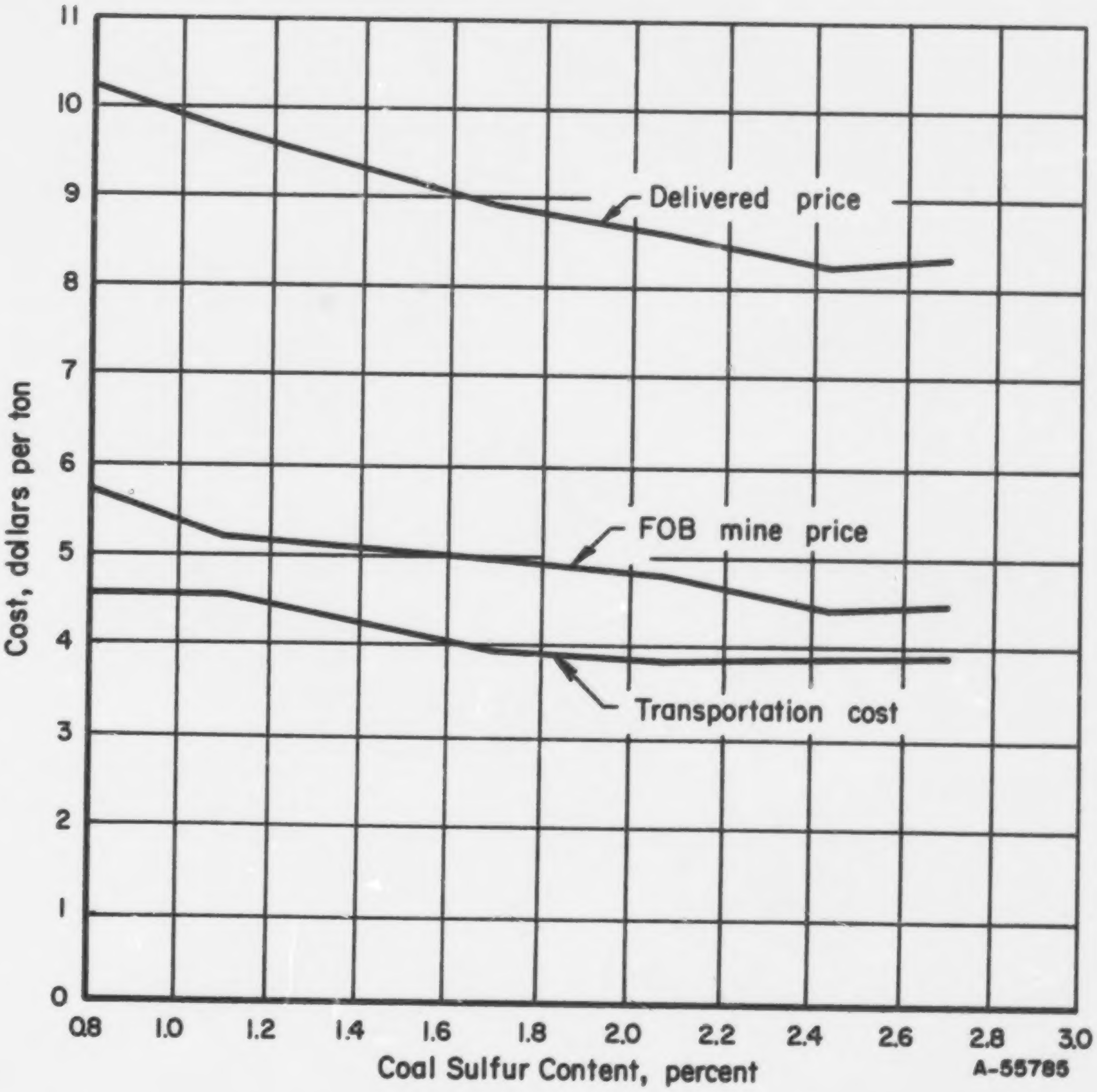


FIGURE 25. AVERAGES OF 59 PRICE QUOTATIONS (7/68) FOR COAL DELIVERED TO PUBLIC SERVICE ELECTRIC AND GAS COMPANY'S HUDSON GENERATING STATION (455 Mwe), JERSEY CITY, N. J., AS A FUNCTION OF SULFUR CONTENT

TABLE 9. COST OF FUEL OIL ($/BBL) FOR VARIOUS PUBLIC SERVICE ELECTRIC AND GAS CO. GENERATING STATIONS AND FOR DIFFERENT SULFUR CONTENTS (August 1, 1968)

	Essex Marion (Hudson)	Kearny	Sewaren	Linden	Burlington
Bunker C - 2.5% Sulfur					
Pipe			1.99 (4-67)[(a)]		
Barge	2.09 (10-67)	2.06 (4-67)			
Lo-Sulfur - 1.0% Sulfur					
Pipe			2.25		
Barge	2.30	2.30			
Hi-Vis - 2.0% Sulfur					
Pipe			1.91 (4-68)		
Hi-Vis, Low-Sulfur 1.0% Sulfur					
Pipe			2.25		
Bunker C - 2.0% Sulfur					
Pipe				2.05 (10-67)	
Lo-Sulfur - 1.0% Sulfur					
Pipe				2.35	
Hi-Vis - 2.3% Sulfur					
Pipe				1.76 (4-68)	
Lo-Sulfur - 1.0% Sulfur					
Barge					2.30
Hi-Vis - 1.6% Sulfur					
Barge					1.92 (4-68)
Lo-Sulfur - 1.0% Sulfur					
Barge					2.50 (2.40)

(a) ( ) - Price at date of discontinuance.

Table 10 presents the heat rates for generating units over 300 Mw and for stations where the average size of unit is over 300 Mw. This table is slightly biased toward the better heat rates because poor unit heat rates are not available for individual units. However, it does not appear that many poor heat rates were missed.

The heat rates in Table 10 were obtained from the 1965 and 1966 editions of Steam-Electric Plant Construction Cost and Annual Production Expenses, published by the FPC.(3)

The heat rate of an individual plant tends to increase with time because of an increased number of stops and starts and because of poorer operating conditions. Therefore the very good heat rates for the newer plants probably will not be maintained. The Eddystone plant has a heat rate about 400 Btu/kwhr less than its contemporaries. However, the Eddystone plant was twice as expensive as other plants of similar size.

The heat rate also depends upon the type of fuel. When calculating the heating value of the fuel it is assumed that the water in the fuel, and the water formed by the combustion of hydrogen, will be condensed, a condition obviously not obtained in a boiler. About 4 percent of the heating value of coal, 7 percent of the heating value of oil, or 10 percent of the heating value of gas is not available because of the water vapor in the flue gas. The heat rates when burning oil and gas therefore are consistently less than the heat rates when burning coal.

Twenty-one units of all sizes had heat rates under 9000 Btu/kwhr. These are all fairly new plants and their heat rates are expected to become poorer as they become older. The best heat rate obtained with any plant is 8,667, only 4 percent less than 9,000 Btu/kwhr. With the present high money rates, and with nuclear plants taking over in high-fuel-cost areas, it appears that the capital costs rather than fuel costs will be reduced in the near future. Therefore, a rapid decrease in the heat rates of new plants is not expected. A 9,000 Btu/kwhr rate for new coal facilities is thus recommended. Gas and oil plants will probably be of similar design, and correcting for the lower net heating value of the fuel, the rates will be 9,350 and 9,700 Btu/kwhr for oil and gas.

The heat rate probably can be estimated more closely than any other cost factor in the model. The differences in heat rates between the best and poorest coal plants are about 10 percent. The differences in size, age, and other factors appear small compared with expected variations in other parts of the model. However, it is recommended that a different heat rate be used for the different fuels because of well-established differences. These differences may be important if incremental costs between fuels are compared, even though the total cost change may be insignificant.

Recommended Values

It is recommended that the heat rate for coal-fired plants be estimated at 9,000 Btu/kwhr, oil-fired plants at 9350 Btu/kwhr, and gas-fired plants at 9,700 Btu/kwhr.

TABLE 10. HEAT RATES FOR 300 Mw AND LARGER ELECTRIC GENERATING UNITS(3)

Plant or Unit	Heat Rate, Btu/kwhr	Rating-Units, Mw	Start-Up Date
	Coal Fired		
Brunner Island	9508	768-2	1961
Eddystone No. 1	8735	354-1	1960
Eddystone No. 2	8795	354-1	1960
Chalk Point	8762	727-2	1964
Hudson	9339	454-1	1964
Breed	8957	450-1	1960
Sporn No. 5	9049	496-1	1960
River Rouge	9450	933-3	1956
Roxboro	9224	410-1	1966
Marshall	8691	700-2	1965
McDonough	9252	600-2	1963
Colbert "B"	9520	550-1	1965
Paradise No. 1	9010	704-1	1963
Paradise No. 2	8900	704-1	1963
Widow's Creek "B"	9350	1125-2	1961
Coffeen	9930	330-1	1965
South Oak Creek	9144	860-3	1959
Joliet	10,014	1862-8	1917
Will County	9616	1268-4	1955
Tanners Creek No. 4	8764	580-1	1964
St. Clair No. 6	9010	353-1	1961
St. Clair No. 5	9060	358-1	1961
Marshall	8712	354-1	1965
Gallatin	9190	1255-4	1956
Branch	9692	300-1	1965
Mt. Storm	9452	1140-2	1965
	Oil Fired		
New Boston	9034	359-1	1965
Cape Kennedy	9461	369-1	1965
Port Everglades	9816	1254-3	1960
Port Everglades No. 3	9482	402-1	1964
Sewaren			
	Gas Fired		
Ritchie	9902	359-1	1961
Robinson	9694	404-1	1966
Handley No. 3	9610	405	1963
Little Gypsy	9815	668-2	1961
Stryker Creek No. 2	9794	527-1	1965
Webster No. 3	9726	389-1	1965
Sabine	9891	952-3	1962

TABLE 10. (Continued)

Plant or Unit	Heat Rate, Btu/kwhr	Rating-Units, Mw	Start-Up Date
	Mixed Fuels		
Mostly Coal			
Arthur Kill	9389	376-1	1959
Mercer	9266	652-1	1960
Astoria	10,171	1550-5	1953
Waukegan No. 8	9114	389-1	1962
Waukegan No. 7	9185	355-1	1958
State Line No. 4	9236	326-1	1962
Mostly Oil			
Ravenswood	9916	1828-3	1963
Riviera	9694	310-1	1963
Mostly Gas			
Alamitos	9530	1982-6	1956
Allen	9470	990-3	1958
Etiwanda No. 3	9692	333-1	1963
Etiwanda No. 4	9682	333-1	1963
Bergen No. 1	9353	325-1	1959
Bergen No. 2	9331	325-1	1960
El Segundo No. 3	9239	342-1	1964
El Segundo No. 4	9265	342-1	1965
Pittsburg No. 6	9420	326-1	1961
Pittsburg	9798	1277-6	1954
Contra Costa No. 7	9377	359-1	1964
Contra Costa No. 6	9504	359-1	1964
Morro Bay No. 4	9506	359-1	1963
Morro Bay No. 3	9552	359-1	1962

Station Capacity Factor

If cost comparisons are to be made between generating facilities on the basis of some cost per kwhr, then the selection of the appropriate plant capacity factor is crucial since it determines by how many units the capital costs and carrying charges are to be divided. Capacity factor is defined as follows:

$$\text{Capacity Factor} = \frac{\text{Kwhr generated in a given time period}}{\text{Nameplate kw rating X hours in the time period}}$$

The usual operating procedure for a utility on any given day is to increase the portion of the load being carried by those generating facilities with the lowest incremental fuel cost first. As these efficient units are loaded to capacity, less efficient units with higher unit fuel costs are started next The reverse procedure is followed as system load declines. Because the newer power plants are usually the most efficient, and therefore have the lowest incremental fuel costs, these are the units that are started first and shut down last. They are the generating units with the highest capacity factor. One limit on any unit's capacity factor is its expected outage rate. Thus, the typical history of a generating unit is that its capacity factor may be modest (50 to 70 percent) in the first year or two of operation until the many operating and equipment difficulties have been resolved. Over the next 5 years, it will probably remain among the most efficient plants in the system, and its capacity factor should range between 70 and 85 percent unless unusual maintenance is required. More efficient plants should be available and operating in the remainder of a 20-year period, and the capacity factor should gradually decline to within the 40 to 60 percent range. Finally, in the later stages of its useful life, the unit will be relegated more and more to peaking duty, and its capacity factor will further decline to the 20 to 40 percent range. Unless the unit is unusually efficient for its time, the average capacity factor for a unit over its life should not differ substantially from the average system capacity factor.

Table 11 lists the average capacity factor for each United States' census region and the United States' average. There are only minor deviations from the nation's average in individual census regions with the exception that the capacity factors are higher in industrialized urban regions and are lower in the rural areas. Individual-utility average capacity factors deviate more widely. As an example, Ohio Power Company, located in the East North Central Region has a capacity factor approaching 70 percent. Nevertheless, for fossil-fuel-fired steam plants, the average data in Table 11 should provide satisfactory accuracy for use in the model.

Adequate operating experience has not been acquired for nuclear facilities to make their historic capacity factors meaningful. Many utilities are estimating 75 to 85 percent capacity factors for nuclear facilities when making the investment decision. This figure which is higher than system average, is justified on the basis that although the anticipated average cost of electricity generated by a nuclear station will be close to that of a fossil-fired unit, the incremental fuel cost is much lower. As discussed in the section on Nuclear Generation, carrying charges comprise a significant portion of the cost of nuclear generation. Thus, the utilities reason that the first nuclear facility they install will have a capacity factor higher than system average. However, as more and more nuclear plants are added to any one system, their individual capacity factors must drop and approach the system averages. This tendency is estimated in Table 12 which is a projection of United

TABLE 11. AVERAGE GENERATING-STATION CAPACITY FACTOR BY U. S. CENSUS REGION - 1966 ESTIMATES(14)

Census Region	Conventional Steam Plants	Identification of States in Census Regions
New England	57.9	Maine New Hampshire Vermont Massachusetts Rhode Island Connecticut
Middle Atlantic	55.4	New York New Jersey Pennsylvania
East North Central	58.0	Ohio Indiana Illinois Michigan Wisconsin
West North Central	49.9	Minnesota Iowa Missouri North Dakota South Dakota Nebraska Kansas
South Atlantic	55.5	Delaware Maryland District of Columbia Virginia West Virginia North Carolina South Carolina Georgia Florida
East South Central	55.2	Kentucky Tennessee Alabama Mississippi
West South Central	49.2	Arkansas Louisiana Oklahoma Texas
Mountain	47.1	Montana Idaho Wyoming Colorado New Mexico Arizona Utah Nevada
Pacific	52.6	Washington Oregon California
U. S. Average	53.4	

TABLE 12. HISTORIC AND ESTIMATED FUTURE UNITED STATES' AVERAGE CAPACITY FACTOR BY ENERGY SOURCE(15)

	1955	1965	1975	1985
Year End Capacity, thousands Mw				
Coal	60	125	214	323
Gas	22	47	83	125
Oil	8	17	27	36
Hydro	25	45	63	89
Nuclear	0	1	68	277
Total	115	235	455	850
Energy Generated, billions Kwhr				
Coal	302	571	865	1,155
Gas	95	222	380	500
Oil	37	65	95	110
Hydro	113	193	250	320
Nuclear	0	4	430	1,615
Total	547	1,055	2,020	3,700
Average Annual Capacity Factor, %				
Fossil (Coal, Gas, Oil)	58.3	53.5	49.3	42.9
Hydro	53.8	51.3	46.1	42.0
Nuclear	--	42.3	80.0	70.0
Weighted Average	56.7	53.6	52.3	51.3

States' average capacity factors for various forms of generation. It shows estimated average capacity factors for nuclear facilities of 80 percent in 1975 but of only 70 percent by 1985. Finally, it must be noted that as the installation of more and more nuclear facilities with capacity factors higher than the system average are projected for the future, the capacity factors of the remaining fossil-fired stations must fall below the system averages.

Recommended Values

It is recommended that the average station capacity factors of Table 11 be used whenever better, more specific information is not available.

Sulfur Dioxide-Control Devices

The cost of a sulfur-control device to the electric consumer depends upon the direct cost of the device and upon the extra cost incurred from losses in transmission because of the more expensive power. However, the latter cost is small and consequently the major cost to the consumer is for the operation of the sulfur-control device. Therefore, the assignment of an arbitrary cost to the sulfur-control device is almost identical to the assignment of an arbitrary incremental cost to the consumer.

How the data available at one operating condition were extrapolated to other operating conditions is described below. The Katell studies for 800 Mw plants using the alkalized-alumina and the catalytic-oxidation processes have been used for the cost base.

Data

The data used for developing costs of sulfur-control devices are those presented by Katell.(16) Katell's cost data, summarized in Table 13, are specifically for 800-

TABLE 13. CAPITAL AND OPERATING COSTS FOR SULFUR DIOXIDE CONTROL DEVICES(16)

	Capital Requirement(a)		Operating Cost(b) (90% Operating Load)			
Process	Dollars	$/Kw	$/Yr	Mills/Kwhr	$/Ton of Coal	Mills/10^4 Btu
Alkalized alumina	8,510,000	10.64	3,402,000	0.537	1.54	60.0
Catalytic oxidation	16,999,000	21.25	3,881,000	0.613	1.75	68.4

(a) Includes plant cost, interest during construction, and working capital.

(b) Includes raw materials, utilities, labor, maintenance, overhead, and capital charges of 14% of total investment but excludes by-product credit.

Mw(e) plants burning coal with a 3 percent sulfur content and operating at a 90 percent load factor. Recently Katell(17) has modified one component of the annual cost, the payroll overhead, by increasing it to 25 percent of payroll.

Other data are being developed for the National Air Pollution Control Administration by other contractors but are not yet available. Chilton(18) has presented many methods of extrapolating costs from one level of operation to another. Basically the 0.6 power rule, with modifications, is recommended.

Other cost data have been presented by Johswich(19), Katell and Plants(17), Bienstock, Field, Katell, and Plants(20), Field, Brunn, Haynes, and Benson(21), and Kiyoura(22), and in an article in Sulphur(23). The data of Katell(16) were used because they were the most detailed.

When using the model, costs for many plant sizes and operating conditions are necessary. Therefore the assumptions below were used to extrapolate Katell's data other plant sizes and operating conditions.

(1) Capital costs are an 0.6 power function of size.

(2) Catalyst and absorbent costs are proportional to size.

(3) The size of the absorbing section of the sulfur control device is proportional to the negative logarithm of the fraction of sulfur not removed from the stack gas.

(4) The size of the desorption and sulfur-processing section of the device is proportional to the sulfur recovered.

(5) Manpower requirements are constant.

(6) Some operating and maintenance costs are proportional to the capital cost.

(7) Other operating expenses are proportional to the power generated.

(8) Still other expenses are proportional to the amount of sulfur recovered.

(9) Payroll overhead is 25 percent.

From these assumptions, the equations below were developed for capital and operating costs. The procedure followed was to express each of the above nine cost components as a function of plant size, etc., using the data of Table 13. The coefficients of like terms were then aggregated to obtain the capital-cost equation:

Capital Cost =

$$C_1 \times (MW)^{0.6}$$

$$+ \quad C_2 \times \left[MW \times \log_{10} \left(\frac{667\ S}{SO_2} \right) \right]^{0.6}$$

$$+ \; C_3 \times [MW \times (667S - SO_2)]^{0.6}$$

$$+ \; C_4 \times MW$$

$$+ \; C_5 \times MW \times \log_{10}\left(\frac{667S}{SO_2}\right)$$

$$+ \; C_6 \times MW \, (667S - SO_2) \quad ,$$

where

C_1, C_2, etc. = aggregated coefficients

MW = plant rating, Mw

S = sulfur content of coal, percent

SO_2 = allowable SO_2 emission, ppm.

Similarly, the operating-cost equation can be expressed as:

$$\text{Cost} = A_1 \times \text{labor rate}$$

$$+ A_2 \times \text{capital cost}$$

$$+ A_3 \times MW \times LF$$

$$+ A_4 \times MW \times LF \times \log_{10}\left(\frac{667S}{SO_2}\right)$$

$$+ MW \times LF \times (667S - SO_2) \times (A_5 + A_5C \times \text{price coal} - A_5S \times \text{price sulfur}),$$

where A_1, A_2, etc., A_5C and A_5S are aggregated coefficients and LF is the load factor.

At present this cost has been calculated as a recurring cost not including financial factors. However, the financial factors, amortization, insurance, profit, interest, etc., could easily be included by adding the appropriate amount to A_2. In the procedure developed and presented in this report, however, an alternative method has been used. The procedure developed is discussed in another section.

For an individual process, several of the aggregated coefficients have been found to be zero. Table 14 lists values of the coefficients for two SO_2-control devices. The constants for other control devices could be determined from one detailed cost breakdown.

The method of cost estimating is as accurate as the present cost estimates. Within one process, the estimates indicate with reasonable accuracy how costs change with changes in the various independent variables. When comparing different processes, the cost data probably are not sufficiently reliable and should not be used to determine the lowest cost alternative. As more accurate cost data become available, the coefficients in the equations can easily be reevaluated.

TABLE 14. COEFFICIENTS FOR COST-ESTIMATING RELATIONSHIPS

Coefficient	Process Alkalized Alumina	Catalytic Oxidation
C_1	0	293
C_2	66,700	0
C_3	890	0
C_4	0	0
C_5	0	0.87
C_6	0.24	0
A_1	59,000	59,000
A_2	0.062	0.062
A_3	0	0
A_4	1,370	398
A_5	0	0.07
A_5C	0.120	0
A_5S	0.046	0.046

The pattern of costs for the alkalized-alumina and catalytic-oxidation processes are different. The catalytic-oxidation process should be more advantageous than the alkalized-alumina for the largest plants operating at the highest load factors, with the maximum sulfur removal, and with the highest-sulfur coals.

Recommended Procedure

If data are available for the specific operating conditions, it is recommended that these data be used. If they are not available, it is recommended that cost be determined from Figues 26 through 29, which are graphical solutions for the equations discussed above but do not include a sulfur credit. If the operating conditions are such that the costs cannot be read from the figures, then the equations should be used with the aggregated coefficients given in Table 14.

Sulfur Content of Fuels

With the advent of SO_2- pollution controls, a premium is being placed on low-sulfur fuels, and high-sulfur fuels may sell at a discount. At present, sulfur-control regulation is just starting to affect the prices, and the final price structure can only be estimated. Presumably, low-sulfur coal eventually will sell at a premium equivalent

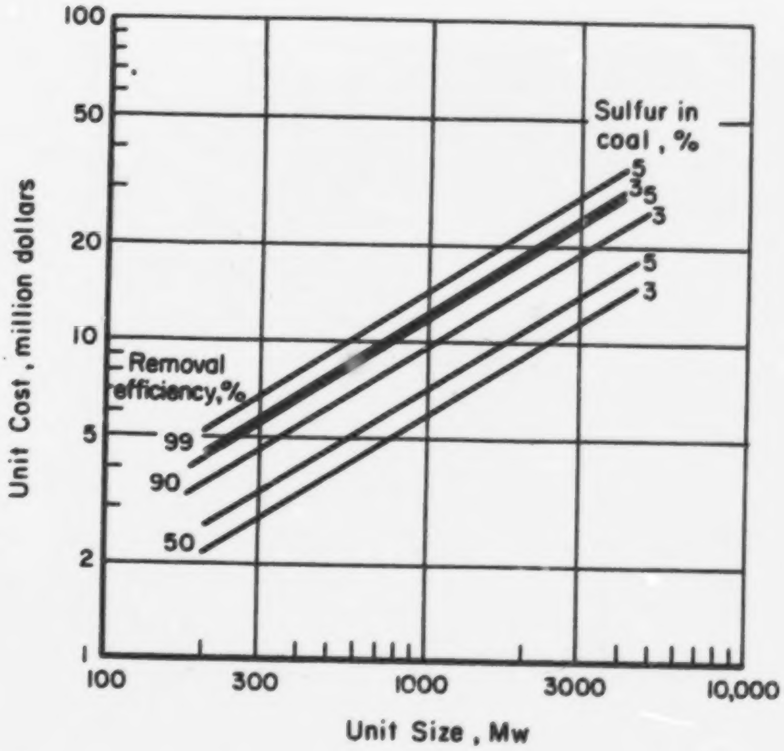


FIGURE 26. CAPITAL COSTS FOR ALKALIZED-ALUMINA-TYPE SO_2 CONTROL DEVICE

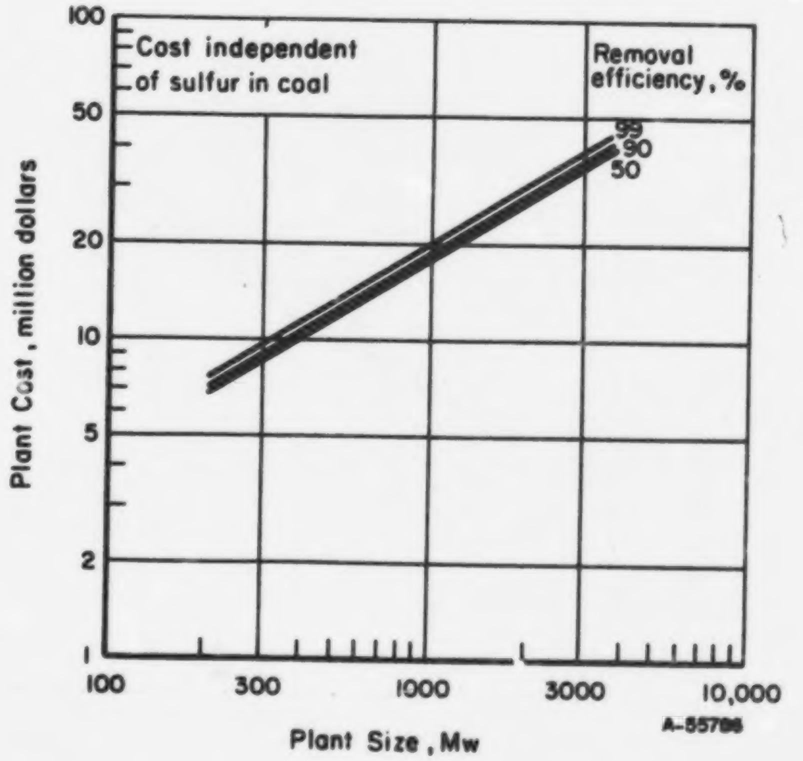


FIGURE 27. CAPITAL COSTS FOR CATALYTIC-OXIDATION-TYPE SO_2 CONTROL DEVICE

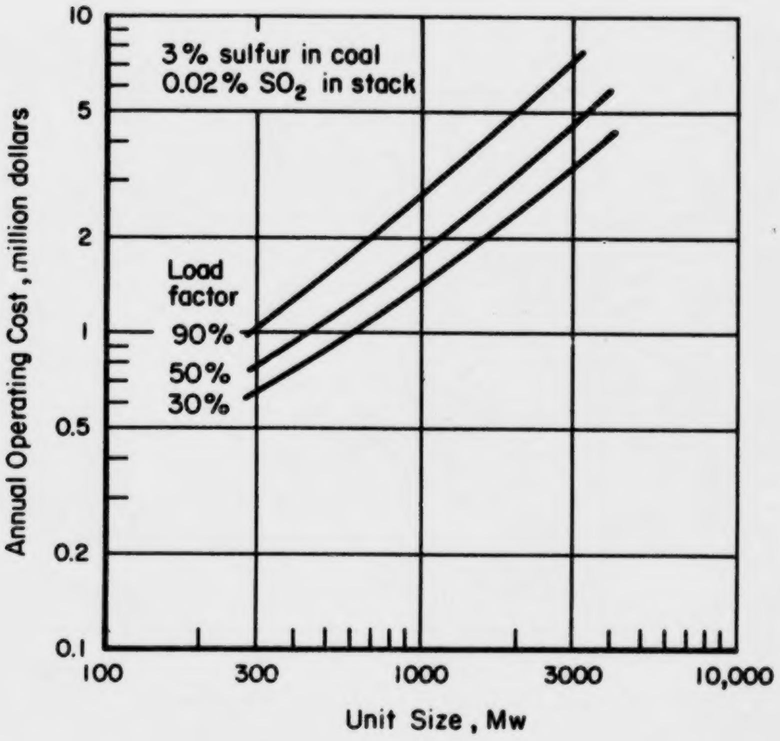


FIGURE 28. OPERATING COSTS FOR ALKALIZED-ALUMINA PROCESS

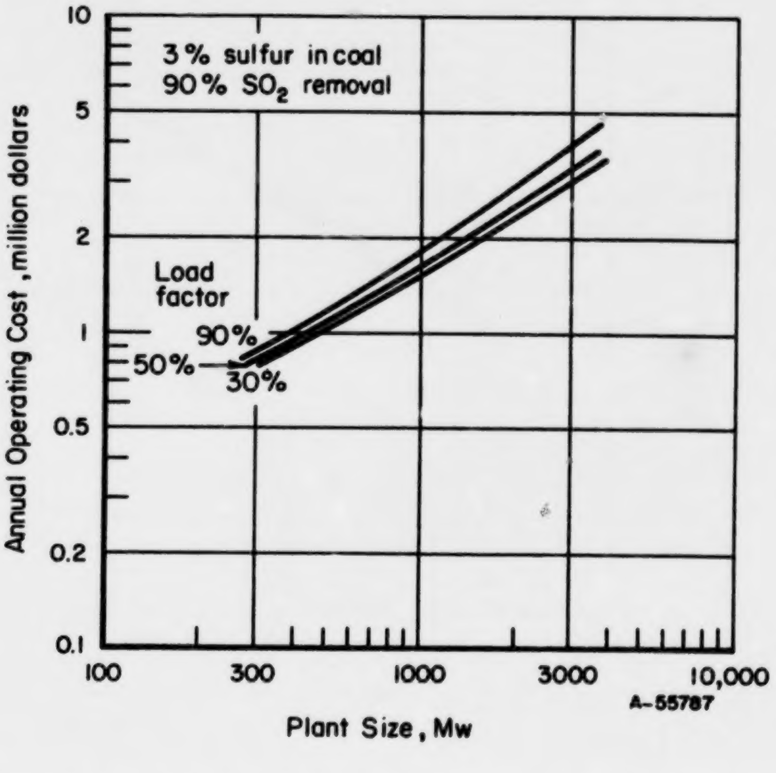


FIGURE 29. OPERATING COSTS FOR CATALYTIC-OXIDATION PROCESS

TABLE 15. SHIPMENTS AND SULFUR CONTENT OF BITUMINOUS COAL TO ELECTRIC UTILITIES IN 1964, BY FINAL DESTINATION(24)

Final Destination and District of Origin	Bituminous Coal, thousand short tons	Sulfur Content, percent	
		Range	Average
New England States			
Massachusetts from district--			
1	562	1.0-3.6	1.5
2	149	1.2-2.8	1.8
3 and 6	713	0.7-3.6	2.1
7	35	0.5-0.7	0.7
8	1,967	0.6-2.0	0.8
Subtotal	3,426	0.5-3.6	1.2
Connecticut from district--			
1	2,461	1.0-3.1	1.7
3 and 6	1,329	0.7-3.6	2.7
7	24	0.7	0.7
8	171	0.9	0.9
Subtotal	3,985	0.7-3.6	2.0
Maine, New Hampshire, Vermont, Rhode Island from district--			
2	8	1.5	1.5
3 and 6	389	1.0-3.6	2.6
8	392	0.8-1.0	1.0
Subtotal	789	0.8-3.6	1.8
Total New England States	8,200	0.5-3.6	1.6
Middle Atlantic States			
New York from district--			
1	3,979	1.0-3.6	1.9
2	481	1.1-2.8	1.6
3 and 6	7,130	0.7-3.6	2.1
4	194	2.6	2.6
8	1,096	0.5-3.1	0.9
Subtotal	12,880	0.5-3.6	1.9
New Jersey from district--			
1	1,702	1.0-3.1	1.6
2	246	1.1-2.0	1.5
3 and 6	3,723	0.7-3.6	2.4
7	27	0.7	0.7
8	31	0.6-1.7	0.8
Subtotal	5,729	0.6-3.6	2.1

TABLE 15. (Continued)

Final Destination and District of Origin		Bituminous Coal, thousand short tons	Sulfur Content, percent Range	Sulfur Content, percent Average
Middle Atlantic States (Continued)				
Pennsylvania from district--				
1		8,830	1.0-3.6	1.7
2		6,096	1.1-4.1	1.8
3 and 6		4,904	0.7-3.6	2.4
4		4	2.0-3.6	2.2
	Subtotal	19,836	0.7-4.1	1.9
Total Middle Atlantic States		38,445	0.5-4.1	1.9
East North Central States				
Ohio from district--				
1		729	2.2-3.1	2.7
2		1,065	1.1-4.1	2.4
3 and 6		2,421	0.7-3.8	2.7
4		15,604	1.6-5.0	3.7
7		1	0.7	0.7
8		2,099	0.5-1.7	0.8
9		1,850	2.7-4.0	3.1
	Subtotal	23,769	0.5-5.0	3.2
Indiana from district--				
8		543	0.6-1.3	0.9
9		5,915	2.0-4.0	2.9
10		1,787	1.2-4.1	3.1
11		8,774	1.1-5.3	3.3
	Subtotal	17,019	0.6-5.3	3.1
Illinois from district--				
7		1	0.7	0.7
8		34	0.5-2.9	1.0
9		2,852	2.0-4.0	2.8
10		19,706	1.1-4.1	2.8
11		402	1.1-4.5	2.9
	Subtotal	22,995	0.5-4.5	2.8

TABLE 15. (Continued)

Final Destination and District of Origin	Bituminous Coal, thousand short tons	Sulfur Content, percent	
		Range	Average
East North Central States (Continued)			
Michigan from district--			
1	310	1.2-2.8	2.0
2	2	2.8	2.8
3 and 6	549	0.7-3.6	2.8
4	6,320	1.6-4.5	3.2
7	20	0.7	0.7
8	6,532	0.5-2.9	0.9
9	756	2.0-4.0	2.9
10	201	1.6-3.7	2.7
Subtotal	14,690	0.5-4.5	2.1
Wisconsin from district--			
2	53	1.1-2.2	1.5
3 and 6	336	1.2-3.6	2.3
4	266	2.2-3.1	2.9
7	19	0.7	0.7
8	382	0.6-1.3	0.8
9	1,917	2.0-4.0	2.8
10	3,594	1.1-4.1	2.4
11	96	1.1-4.5	3.0
Subtotal	6,663	0.6-4.5	2.4
Total North Central States	85,136	0.5-5.3	2.8
West North Central States			
Minnesota from district--			
2	1	1.8	1.8
3 and 6	193	3.5-3.6	3.6
4	350	1.6-3.1	3.0
7	15	0.7	0.7
8	209	0.7-0.8	0.8
9	90	2.0-2.9	2.6
10	2,344	1.1-4.1	2.9
15	65	3.0	3.0
21	582	0.7-1.0	0.8
Subtotal	3,849	0.7-4.1	2.5
Iowa from district--			
10	1,397	1.1-4.1	3.0
11	1	3.9	3.9
12	747	4.2-5.7	4.7
15	174	3.0-6.0	5.1
Subtotal	2,319	1.1-6.0	3.7

TABLE 15. (Continued)

Final Destination and District of Origin	Bituminous Coal, thousand short tons	Sulfur Content, percent	
		Range	Average
West North Central States (Continued)			
Missouri from district--			
9	10	2.7-4.0	3.1
10	2,651	1.1-4.1	2.9
15	2,757	3.0-6.0	4.0
Subtotal	5,418	1.1-6.0	3.5
North and South Dakota from district--			
10	1	1.2-4.1	3.1
19	188	0.6-1.0	0.9
21	1,115	0.7-1.0	0.8
Subtotal	1,304	0.6-4.1	0.8
Nebraska and Kansas from district 15	925	3.0-6.0	3.7
Total West North Central States	13,815	0.6-6.0	3.0
South Atlantic States			
Delaware and Maryland from district--			
1	3,611	1.0-3.1	1.8
2	428	1.5	1.5
3 and 6	1,572	0.7-3.5	2.0
8	165	0.5-1.1	0.9
Subtotal	5,776	0.5-3.5	1.8
District of Columbia from district--			
1	343	1.0-2.5	1.5
3 and 6	7	2.2	2.2
	24	0.5-0.7	0.7
Subtotal	374	0.5-2.5	1.5
Virginia from district--			
7	503	0.5-1.1	0.7
8	7,321	0.5-3.1	1.0
Subtotal	7,824	0.5-3.1	1.0
West Virginia from district--			
3 and 6	3,699	0.7-3.8	3.2
4	919	2.1-5.0	3.3
8	3,009	0.6-2.1	1.4
Subtotal	7,627	0.6-5.0	2.5

TABLE 15. (Continued)

Final Destination and District of Origin	Bituminous Coal, thousand short tons	Sulfur Content, percent	
		Range	Average
South Atlantic States (Continued)			
North Carolina from district--			
7	305	0.5-0.9	0.7
8	8,182	0.5-3.1	0.9
Subtotal	8,487	0.5-3.1	0.9
South Carolina from district--			
7	46	0.7	0.7
8	2,555	0.5-3.1	1.0
Subtotal	2,601	0.5-3.1	1.0
Georgia and Florida from district--			
8	3,723	0.5-3.1	1.6
9	1,734	2.0-4.0	3.0
13	575	0.7-1.6	0.9
Subtotal	6,032	0.5-4.0	1.9
Total South Atlantic States	38,721	0.5-5.0	1.5
East South Central States			
Kentucky from district--			
8	889	0.5-2.6	1.2
9	7,246	2.0-4.0	3.0
10	3,046	1.1-4.1	2.1
Subtotal	11,181	0.5-4.1	2.6
Tennessee from district--			
7	20	0.7	0.7
8	5,729	0.5-4.3	1.8
9	4,662	2.0-4.0	3.1
10	184	2.5	2.5
13	475	1.6	1.6
Subtotal	11,070	0.5-4.3	2.4
Alabama and Mississippi from district--			
9	5,013	2.0-4.0	2.9
10	69	2.5	2.5
13	6,918	0.7-1.7	1.1
Subtotal	12,000	0.7-4.0	1.9
Total East South Central States	34,251	0.5-4.3	2.2

TABLE 15. (Continued)

Final Destination and District of Origin		Bituminous Coal, thousand short tons	Sulfur Content, percent	
			Range	Average
West South Central States				
Arkansas, Louisiana, Oklahoma, Texas from district 15		18	4.0	4.0
Mountain States				
Colorado from district--				
16		535	0.3-0.7	0.5
17		1,113	0.5-0.9	0.7
19		284	0.7	0.7
	Subtotal	1,932	0.3-0.9	0.6
Utah from district 20		410	0.6-0.8	0.7
Montana and Idaho from districts 22 and 23		294	0.6	0.6
Wyoming from district 19		1,762	0.6-1.0	0.9
New Mexico from district 18		2,116	1.0	1.0
Arizona and Nevada from district--				
18		426	1.0	1.0
20		30	0.6-0.7	0.7
	Subtotal	456	0.6-1.0	1.0
Total Mountain States		6,970	0.3-1.0	0.8
Pacific States				
Alaska from districts 22 and 23		354	0.7	0.7
Other Destinations				
Canada from district--				
1		259	1.6-2.0	1.7
2		888	1.5	1.5
3 and 6		1,887	1.2-3.5	2.3
8		121	0.6-1.2	0.8
9		20	2.7-4.0	3.1
	Subtotal	3,175	0.6-4.0	2.0

TABLE 15. (Continued)

Final Destination and District of Origin	Bituminous Coal, thousand short tons	Sulfur Content, percent	
		Range	Average
	Other Destinations (Continued)		
Destinations that are not revealable from district--			
1	4	1.8	1.8
2	7	1.8	1.8
3 and 6	27	2.4	2.4
8	100	1.1	1.1
9	48	2.9	2.9
10	9	2.7	2.7
11	75	3.3	3.3
13	3	1.1	1.1
15	11	3.9	3.9
20	23	0.7	0.7
Subtotal	307	0.7-3.9	2.1
Total Other Destinations	3,482	0.6-4.0	2.1
Grand Total	229,392	0.5-6.0	2.3

to the cost of removing sulfur dioxide from the flue gas by the least expensive method. At present, low-sulfur oil in New York sells for 37¢/MM Btu, while high-sulfur oil sells for 28¢/MM Btu. In general, premiums are not charged for low-sulfur coal, except that often the low-sulfur coal mine is farther from the electric plant than is the mine for high-sulfur coal and there is a transportation price differential.

Data

Figure 30(24) shows that in 1964, electric utilities consumed less low-sulfur coal and more medium-sulfur coal than the national averages. Table 15 pinpoints coal shipments to utilities in the year 1964 from specific coal-producing regions.(24) Not only is the tonnage shipped from each producing region to electric utilities presented, but also the range and average sulfur content of those shipments. Figure 31(25) is a map which identifies the various coal-producing regions. As indicated in Table 15, the weighted average of sulfur content for coal burned by electric utilities is 2.3 percent. This is for cleaned coal; for coal not cleaned as is used by some utilities, the sulfur content would be 0.3 to 0.5 percent higher.

Figure 32 shows the oil-using regions and Table 16 shows typical sulfur contents (minimum, average, and maximum) of oils used in these various regions.(26) Trend data indicate that the national arithmetic average sulfur content of 129 samples of fuel oil burned by electric utilities was relatively constant around 1.6 percent in the 5-year period 1960 through 1965.

TABLE 16. SULFUR CONTENT OF NUMBER 6 FUEL OIL(26)

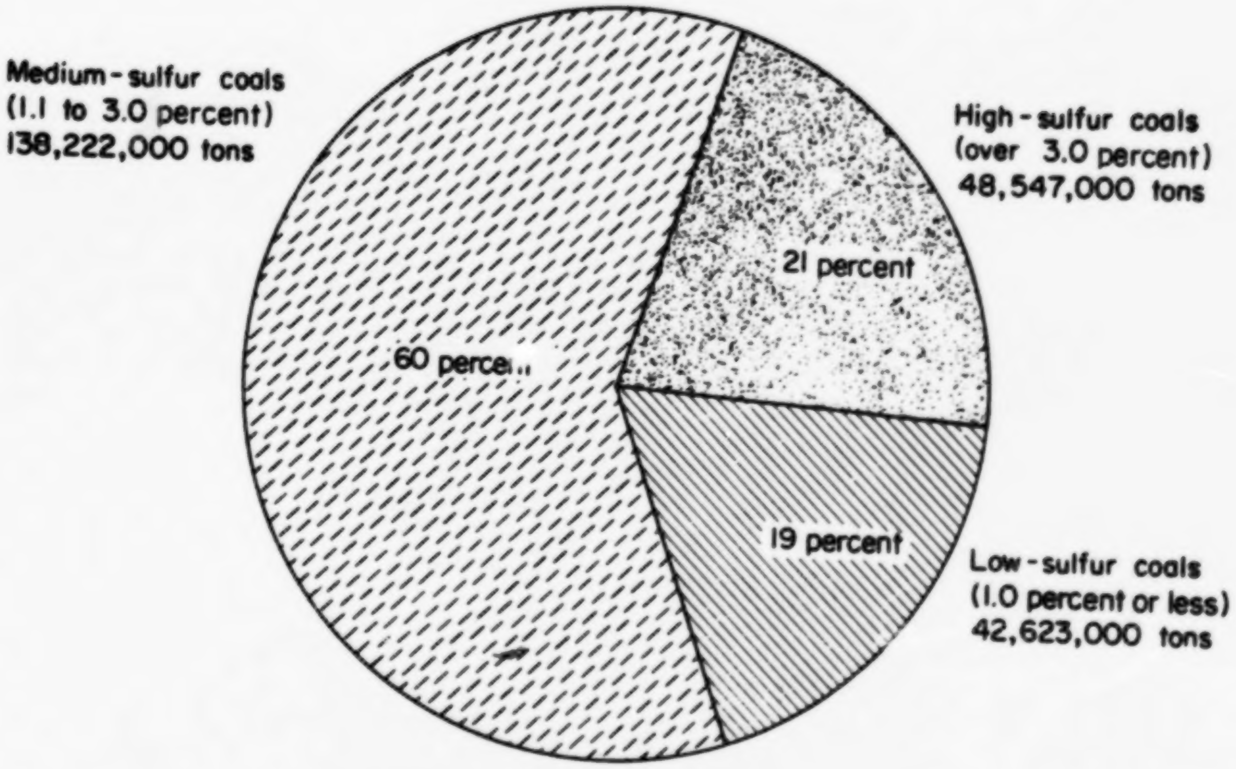
Geographic Distribution of Burner Fuel Oils(a):	Eastern Region			Southern Region			Central Region			Rocky Mountain Region			Western Region		
Districts Within Region:	A, B, C			D			E, F, G			H, I, J, K			L, M, N, O, P		
Additional Districts(b):	D, E, F, G, J			A, B, C, E, F, G, J			A,B,C,D,H,I,J,K,L			E, F, G, H, I, K			E, F, G, H, I, K		
Number of Fuels:	40			15			34			17			23		
Test	Min	Avg	Max	Min	Avg	Max	Min	Avg	Max	Min	Avg	Max	Min	Avg	Max
Sulfur Content, percent	0.47	1.43	2.8	0.48	1.65	3.15	0.38	1.58	4.0	0.45	1.81	4.0	0.87	1.56	4.0

(a) Regions and districts are shown on map (Figure 32).
(b) Some of the fuels are sold in districts of more than one region.

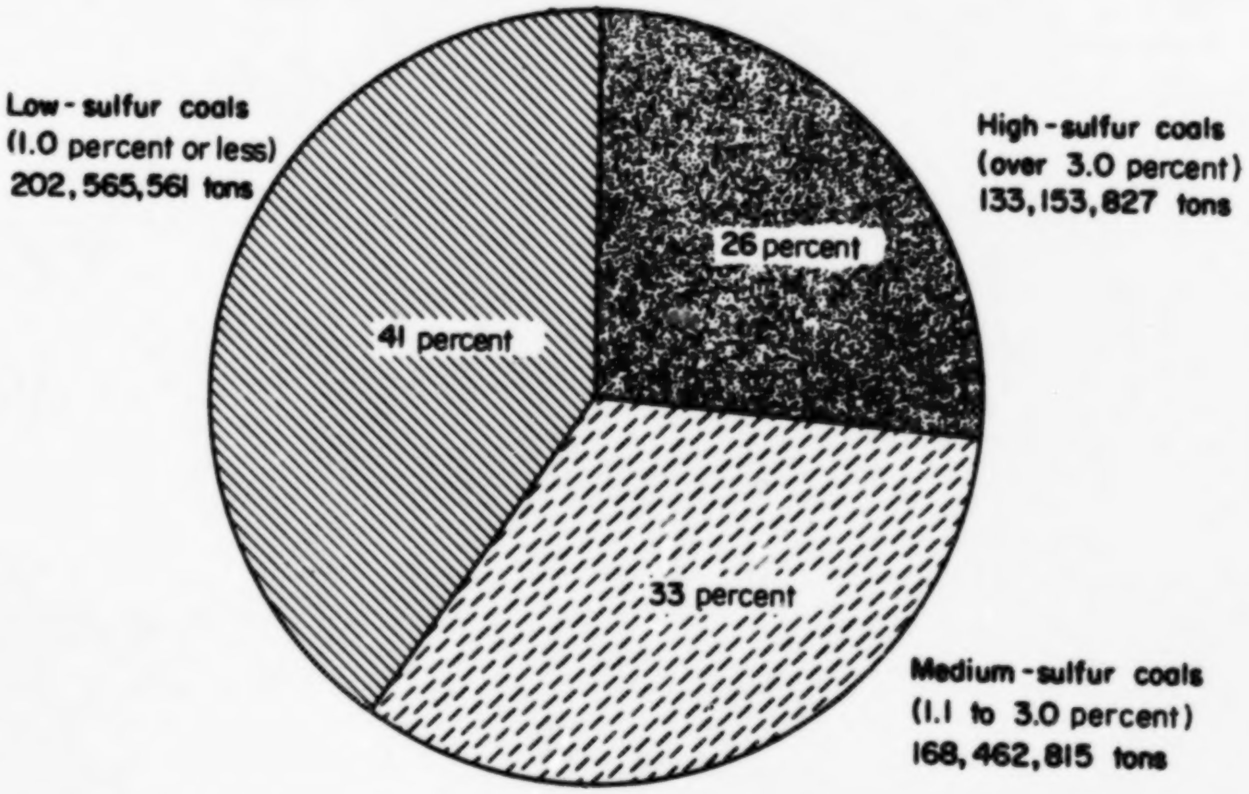
Discussion

The option of burning low-sulfur coal is available only to a few utilities and not to the industry at large because insufficient low-sulfur coal is available. Only about 40 percent of the bituminous coal mined has a sulfur content of less than 1 percent and most of that is used in the manufacture of steel.

A comparison of the coal reserves with the coal production listed by DeCarlo, et al.(24) indicates that the sulfur content of coal will increase as the low-sulfur reserves



a. Shipments of Bituminous Coals to Electric Utility Plants, by Sulfur Content, in 1964 (Includes Subbituminous Coals and Lignite)



b. Production of Coals of All Ranks, by Sulfur Content, in 1964

FIGURE 30. SULFUR CONTENTS OF COAL(24)

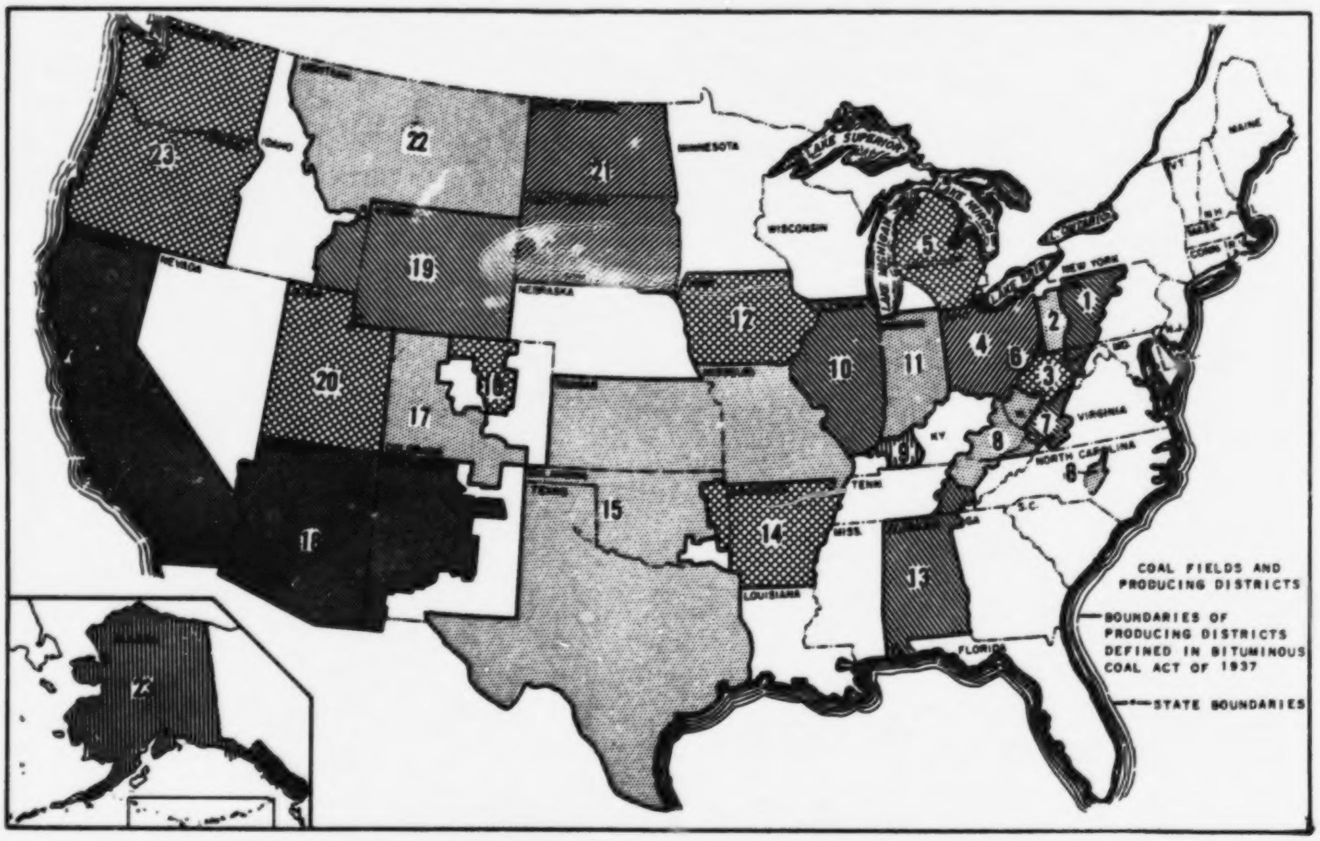


FIGURE 31. MAP OF THE COAL-PRODUCING DISTRICTS OF THE UNITED STATES

District Number and Name

1. Eastern Pennsylvania
2. Western Pennsylvania
3. Northern West Virginia
4. Ohio
5. Michigan
6. Panhandle
7. Southern numbered 1
8. Southern numbered 2
9. West Kentucky
10. Illinois
11. Indiana
12. Iowa
13. Southeastern
14. Arkansas-Oklahoma
15. Southwestern
16. Northern Colorado
17. Southern Colorado
18. New Mexico
19. Wyoming
20. Utah
21. North-South Dakota
22. Montana
23. Washington

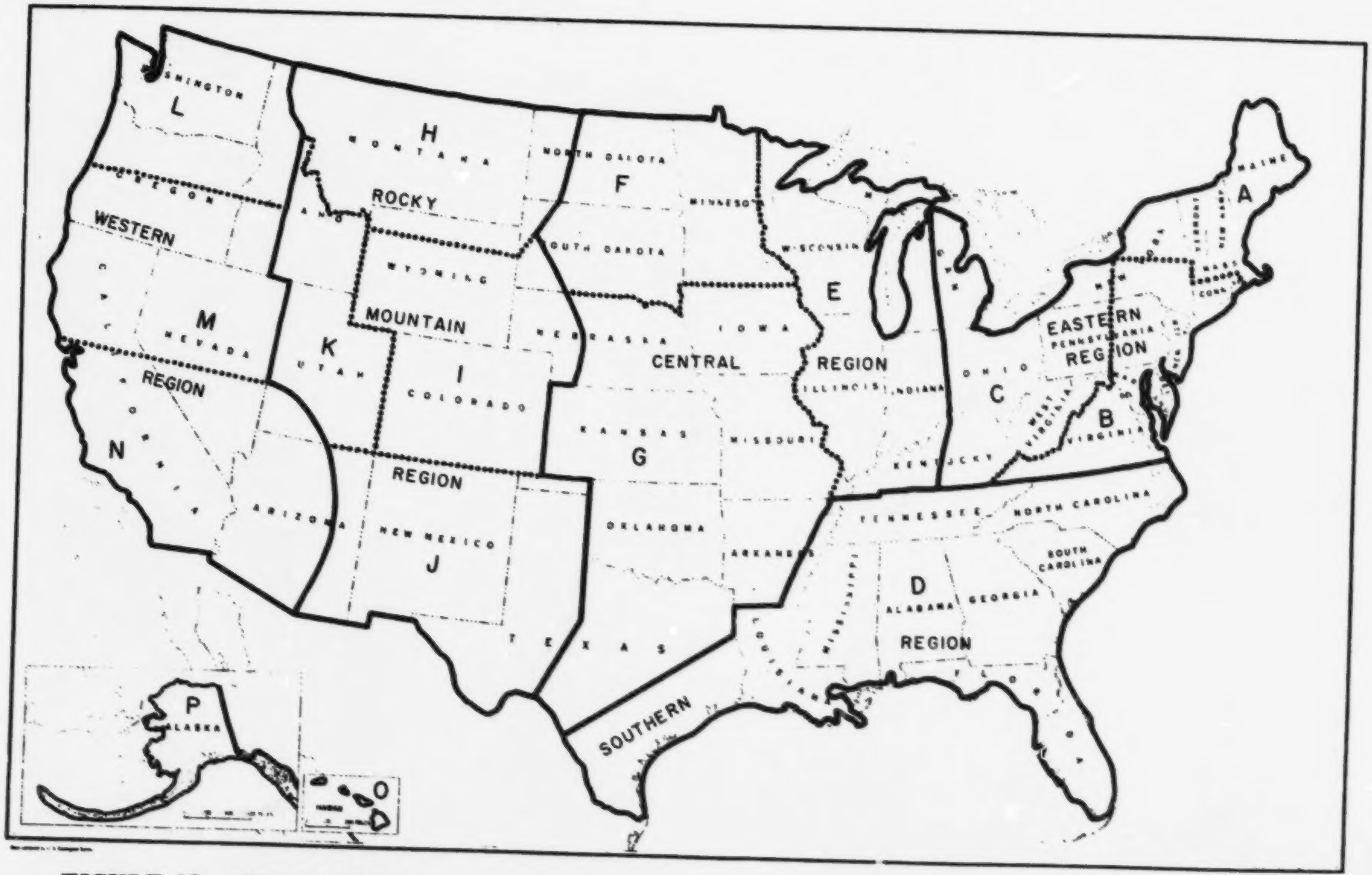


FIGURE 32. GEOGRAPHICAL AREAS OF THE NATIONAL SURVEY OF BURNER-FUEL OILS(26)

are depleted. The steel industry, the second largest user of coal, would be more seriously affected by an increase in the sulfur content of coal than the electric utilities and therefore should be willing to pay a higher premium for low-sulfur coal. Thus, the option of reducing sulfur emmission by the substitution of low-sulfur coal, or the equivalent by deep cleaning or conversion to gas or liquid fuel, for high-sulfur coal will be available only in special cases.

The simplest way to treat the additional cost of low-sulfur coal is to compare the distances from the mines to the generating station and assume that all of the cost differences is due to additional transportation costs. Current data do not permit determining the price differential between coals of different sulfur contents.

Recommended Values

It is recognized that the best information for use in the model for evaluating specific situations might be obtained directly from the electric utility or coal supplier. In a comparison being made between a high-sulfur coal and a low-sulfur coal, quotations for both fuels, if possible on a delivered basis, would be most desirable. However, in most evaluations and, in particular if a hypothetical plant is being considered, the sulfur content of the coal should be taken from Table 15 for the region of use and origination.

The only present basis for comparing the prices of low- and high-sulfur oil is the experience in New York of Consolidated Edision. Therefore, the cost of a low-sulfur oil should be estimated as being 20 percent higher than the applicable high-sulfur-oil cost.

Sulfur Credits

The prospect that substantial quantities of sulfur could be recovered from the stack gases of electric generating facilities poses the problem of determining a probable value for the sulfur. In the context of this program, the value figure needed corresponds to the so-called "net back" that the producer of sulfur realizes from sales at his producing location.

The value of sulfur to the consumer depends on his use of it and the relationship that this bears to the commercial forms of sulfur available to him. The consumer of sulfur who is making sulfuric acid can utilize a wide variety of forms – brimstone (elemental sulfur), pyrites, sulfur dioxide from smelter gas, hydrogen sulfide, certain petroleum sludge acids, etc. Conversely, the consumer of sulfur who is making matches or compounding rubber products has to have brimstone in solid form with specific physical properties and purity requirements. In effect, the markets for sulfur in the United States require the producers to supply a multitude of forms and quality levels, each tailored for its intended end use.

The principal forms in which sulfur is consumed include (1) crude brimstone, either dark or bright, (2) processed sulfur or refined sulfur, and (3) sulfur dioxide derived from roasting of pyrites or nonferrous sulfides. Crude brimstone contains a minimum of 99.5 percent sulfur, and when contaminated with carbon from Frasch-mined deposits, it is known as "dark" crude brimstone, entirely suitable for making sulfuric acid but not acceptable for many other uses. A minor quantity of Frasch-mined brimstone and virtually all the recovered sulfur produced from some natural gas or petroleum refinery off-gas streams is bright crude brimstone, suitable for conversion to processed sulfur or for many nonacid uses. Processed sulfur contains from 93 to 99.9 percent of sulfur, has the characteristic yellow coloration, and is treated to make it suitable for a specific nonacid use, such as rubber compounding, pesticide formulation, or match manufacture. Sulfur dioxide, a gas at ambient temperatures and pressures, is used predominantly for making sulfuric acid in a plant adjacent to the sources of the sulfur dioxide.

Sulfur Consumption

In 1966, the latest year for which "official" data are available, apparent consumption in the United States amounted to about 9.2 million long tons(27) of sulfur equivalent in all forms. This was supplied from domestic production of brimstone, pyrites, and sulfur dioxide in smelter gases and imports of brimstone and pyrites, as shown in Table 17.

These are the only so-called "official" data known to exist with respect to the consumption of all forms of sulfur in the United States. It will be noted that the emphasis for these data is the source of the sulfur and not the use to which it is put or the intermediate products by which this supply is converted to end uses.

"Unofficial" estimates prepared by representatives of the major U. S. Frasch sulfur producers(28) indicate that 82 to 87 percent of the sulfur consumed in the United States is used to make sulfuric acid. The balance of 13 to 18 percent is consumed in a large number of end uses and industries, among which the pulp and paper, industrial chemicals, rubber, and pesticides industries are relatively important. Table 18 presents Gittinger's estimates.(28)

Sulfuric Acid Markets

Neither of the sources of data(27, 28) attempt to detail the geographic distribution of sulfur consumption in the United States. However, data on the production of sulfuric acid is collected and reported by the U. S. Bureau of the Census on a regional basis; from this sulfur consumption can be approximated by applying an appropriate conversion factor. In prior studies, Battelle has developed such a conversion factor that agrees rather well with the "unofficial" estimates for consumption of sulfur in sulfuric acid. To produce 1 short ton of sulfuric acid (100 percent basis) requires approximately 0.3 long tons of brimstone in a modern catalytic acid plant. Although a number of less efficient chamber acid plants are still in use, the application of the 0.3 factor to total new acid produced is an adequate first approximation of regional sulfur consumption for sulfuric acid. Table 19 presents Bureau of the Census data for production of new sulfuric acid in selected geographic areas. To avoid revelation of specific plant data, the distribution by area differs from the usual presentation of the nine standard Census regions.

It will be noted that the several sets of data do not result in a statistically compatible series of numbers for any given year. This results from differences in orientation of the various reporting agencies and their inclusion or exclusion of certain data, for example, the spent acid burned in a number of acid plants located beside petroleum

TABLE 17. APPARENT CONSUMPTION OF SULFUR IN THE UNITED STATES(27)

(Thousands of Long Tons of Sulfur Equivalent)

	1960	1961	1962	1963	1964	1965	1966
Brimstone							
U. S. Frasch crude[a]	3343	3259	3320	3438	3847	4286	5314
U. S. recovered	775	831	907	929	988	1167	1256
Mexican Frasch crude	607	649	746	863	891	831	799
Canadian recovered	134	183	295	488	571	656	715
Subtotal	4859	4922	5268	5718	6297	6940	8084
Pyrites							
U. S. production	416	399	379	344	354	354	356
Canadian imports	146	135	145	93	120	160	160
Subtotal	562	534	524	437	474	514	516
Smelter-Gas Acid	345	332	355	336	366	388	424
Other Production[b]	95	106	98	116	124	139	134
Total[c]	5862	5893	6244	6607	7260	7980	9158

(a) Apparent sales less exports of crude and refined sulfur.

(b) Includes H_2S and SO_2 from certain refineries and smelters.

(c) Detail may not add to total because of independent rounding.

TABLE 18. ESTIMATED CONSUMPTION OF SULFUR IN THE UNITED STATES BY ACID AND NONACID APPLICATION(28)

(Thousands of Long Tons of Sulfur Equivalent)

	1960	1961	1962	1963	1964	1965	1966
Acid Use	4950	4950	5250	5750	6300	6935	7975
Nonacid Use	1050	1050	1050	1100	1150	1190	1225
Total	6000	6000	6300	6850	7450	8125	9200

TABLE 19. PRODUCTION OF NEW SULFURIC ACID AND CALCULATED CONSUMPTION OF SULFUR IN THE UNITED STATES, BY SELECTED AREAS(29)

	1960		1961		1962		1963		1964		1965		1966	
	H_2SO_4 (100%), Mst	Sulfur (All Forms), Mlt	H_2SO_4 (100%), Mst	Sulfur (All Forms), Mlt	H_2SO_4 (100%), Mst	Sulfur (All Forms), Mlt	H_2SO_4 (100%), Mst	Sulfur (All Forms), Mlt	H_2SO_4 (100%), Mst	Sulfur (All Forms), Mlt	H_2SO_4 (100%), Mst	Sulfur (All Forms), Mlt	H_2SO_4 (100%), Mst	Sulfur (All Forms), Mlt
New England	193	58	179	54	184	55	184	55	193	58	207	62	205	62
Middle Atlantic	2,436	731	2,423	727	2,482	745	2,626	788	2,768	830	2,709	813	2,721	816
Pennsylvania	755	227	770	231	797	239	877	263	941	282	972	292	966	290
North Central	3,023	1,087	3,629	1,089	3,819	1,146	4,052	1,216	4,317	1,295	4,355	1,307	4,475	1,343
Illinois	1,356	407	1,399	420	1,464	439	1,562	469	1,697	509	1,704	511	1,763	529
Iowa	82	25	75	23	82	25	90	27	92	28	82	25	99	30
Michigan	324	97	308	92	332	100	356	107	347	104	323	97	342	103
Ohio	742	223	684	205	662	199	659	198	675	203	704	211	689	207
Wisconsin	(a)		(a)		(a)		(a)		(a)		(a)		38	11
South	8,546	2,564	8,731	2,619	9,975	2,993	10,833	3,250	12,117	3,635	13,675	4,103	16,749	5,025
Delaware and Maryland	1,119	336	1,078	323	1,114	334	1,017	305	1,043	313	1,035	311	1,049	315
Florida	2,272	682	2,518	755	3,087	926	3,822	1,147	4,406	1,322	5,558	1,667	7,444	2,233
Texas	1,593	478	1,585	476	1,886	566	1,926	578	2,274	682	2,502	751	2,968	890
West	2,288	686	2,096	629	2,323	697	2,342	703	2,566	770	2,867	860	3,357	1,007
California	1,009	303	924	277	1,057	317	1,049	315	1,163	349	1,398	419	1,423	427
Idaho	(1)		(1)		(1)		(1)		(1)		(1)		737	221
U. S. Total	17,085	5,126	17,058	5,117	18,782	5,635	20,038	6,011	21,959	6,588	23,813	7,144	27,506	8,252

(a) Included with "other" (not reported here) to avoid disclosure of individual plant data.

refineries. This spent acid is included in the Census data but is not recorded elsewhere as a source of sulfur except as a rather gross estimate prepared by "unofficial" sources.

As shown in Table 19, the Middle Atlantic and North Central areas - containing a large share of the industrial production of the country - has had a rather modest growth from 1960 to 1966. The major increase has occurred in the Southern area - especially Florida and Tesas - under the impetus of rapidly expanding markets for phosphatic fertilizers.

For the near-term future - say 1975 - the industrialized northeast is expected to continue the growth pattern of the past few years. On the other hand, the rapid growth of phosphatic fertilizers will be moderated by capacity in excess of demand until the latter part of the period.

Regional Value of Sulfur

Traditionally, Frasch brimstone produced in the Gulf Coast area has been the price leader for sulfur both within the United States and worldwide. Since 1965, the quoted price for brimstone fob Gulf ports has risen from $26.50/long ton for dark crude to the current level of $41.50. To a large extent, the fertilizer buildup in the United States has accounted for a demand in excess of productive capacity for sulfur. Between 1963 and 1967, the production deficit was supplied from producers' stocks, but the prolonged shortfall permitted producers to raise prices without fear of substitution.

Production increases effected in 1966 and 1967, coupled with 2 years of less-than-expected growth in phosphatic fertilizers - also 1966 and 1967 - combined to reestablish the supply-demand balance late in 1967, and the preliminary indication is that some addition will be made to producers' stocks during 1968. Assuming that the producers - worldwide - will be able to meet near-term demands, it is anticipated that the fob Gulf ports quoted price for brimstone will fall to the $30 to $35 range by about 1970 and remain in that range through 1975.

On the basis of the current quoted price - $41.50 fob Gulf ports - brimstone has an approximate value of $48.50 in the New York - New Jersey area, and $50 to $52 in the Chicago or Pittsburgh areas on the basis of ship or barge transportation in molten form. These are the approximate values for sulfur with which sulfur recovered from power plant stacks would compete. By 1970, the comparable values are expected to be $37 to $42 in New York - New Jersey, and $40 to $43 in Chicago and Pittsburgh, assuming that the bulk of the demand will be supplied by shipments from the Gulf Coast. When more than one-third of the local (within a 100-mile radius) demand is available from local sources at prices equivalent to or less than the prevailing Gulf ports price, the local market price will be depressed. Further, if the local area becomes an export center - i.e., produces more than the local demand - the adjacent areas also will experience price depression toward the prevaling Gulf ports price, under the assumption that the local production is in the form of brimstone with quality equivalent to crude Frasch brimstone.

A study of local demand centers in the northeastern part of the United States appears to be necessary to properly assess the impact of any given sulfur-recovery installation from generating-facilities' stack gases.

Recommended Values for Recovered Sulfur

The electric utility recovering sulfur from stack gases will be faced with the problem of disposing of that sulfur and concurrently with the problem of setting a price for it. As indicated in the preceding section, the site of recovery and the sulfur supply/demand relationship in that area will influence the "net back" that the utility could expect. But the costs for selling that sulfur represent expenses that must be deducted from the "net back" to determine the value the utility can credit to the producing installation.

Two principal routes are open to the utility recovering sulfur with respect to disposing of it. Firstly, the utility may decide to handle the marketing of the sulfur on its own and become a competitor for any markets available. Secondly, the utility may elect to arrange for the marketing of the sulfur through an established organization, thus avoiding an entry into the chemical business. The choice between these two alternatives will depend on a number of factors, including the important consideration of the quantity of sulfur involved and the status of the sulfur market in the area.

For preliminary planning purposes, either alternative mentioned above will involve expenses over and above the cost of actually producing the sulfur. These expenses should be deducted from the sales price received in order to determine the credit to the producing facility. When the utility becomes the marketing agent, it can be anticipated that about 20 percent of the sales price will be allocated to selling expenses, general administrative overhead, and profit. Thus, at a sales price of $37/long ton, the credit to the producing facility would be $29.60. If the utility can arrange for sales to be handled by an outside organization, the sales commission might be negotiated to be about 10 percent of the sales price, which would yield a credit to the producing facility of $33.30 on a sales price of $37/long ton.

Between these two alternatives, the latter appears to be the more attractive choice to maximize the value credited to the producing facility. However, it can be anticipated that the established sulfur-marketing organizations might resist such an arrangement, forcing the utility to undertake an independent marketing effort. In the initial operation of the model it is recommended that the assumption be made that the utility will have to handle the marketing of the sulfur and will incur the associated expenses, leaving 80 percent of the sales price as the credit to the producing facility.

Further, the assumption should be made that the effective sales price for sulfur in the period from 1970 to 1975 will be about $30/long ton fob U. S. Gulf ports. This will mean an effective sales price of $37/long ton in the New York area, and $40/long ton in the Chicago or Pittsburgh areas under current supply conditions.

If the recovery process results in the production of sulfuric acid instead of brimstone, the calculation of its value becomes more complex. With sulfur selling for about $48/long ton in New York currently, the quoted price for 100 percent sulfuric acid is $34.65/short ton fob works. One short ton of this acid will contain 0.3 long tons of sulfur having a value of $14.40, the balance being attributable to conversion costs, sales and administrative overhead expenses, and profit. For simplicity, call this figure $20/short ton. Then, with sulfur selling at $37/long ton, the resulting sulfuric acid should sell for $31.10/short ton in the 100 percent grade. This figure would then be reduced by 20 percent to arrive at a credit of $24.90/short ton of acid to the producing facility.

In the event that the recovery process yields a lower strength and contaminated acid, it would be necessary in most locations to process it to a clean 100 percent acid to assure markets for it. On the basis of estimates of concentration and filtration costs, Battelle calculates that a 70 percent acid would have to sell for \$5 to \$6/short ton less than the going market price for 100 percent acid in order to be marketable. Again assuming the \$37/long ton sulfur price, the sales price for the 70 percent acid would be \$25.10 to \$26.10/short ton fob works, with a probable deduction of 20 percent from this as the value credited to the producing facility, say \$20.10 to \$20.90.

By means of these relationships, values for recovered products can be calculated for any sulfur price between \$30 and \$45/long fob Gulf ports. Below \$30 and above \$45, recalculation of the appropriate prices for 100 percent and 70 percent sulfuric acids would be necessary.

Carrying Charges---Treatment of Financial Costs, Depreciation, and Taxes

Although carrying charges quoted by individual utilities are seen to vary considerably because of the items included, at some point in their investment decision each company must consider similar factors. As an example, some companies choose to include a component for "general supervision and maintenance" in their carrying charges. In Battelle's model, all such costs are considered under regular recurring costs (as are property taxes and insurance). Thus, the only elements remaining for separate inclusion as carrying charges are financial costs, depreciation, and gross-receipts and income-based taxes. Because utility returns are predictable, most taxes can be expressed as a percentage of this return, and it is common utility practice to include taxes in their carrying charges.

The effective property-tax rates that are included under recurring costs are derived from Netzer's study,(30) and represent the average of the effective rates applied to all taxable property in a state in 1960. These state averages were in turn combined to derive averages for each FPC District (Table 20). Actual taxes on individual power plants within a single FPC district will vary widely from these averages depending upon location, because the administration of property taxes is highly fragmented. The fact that 1960 statistics are being used should not introduce too much bias in estimating current tax levels as applied to power-generating stations since many of these are located outside of metropolitan areas. Rural areas traditionally have lower property tax rates than metropolitan regions.

The financial components of the carrying charges are subject to less regional variation for two reasons: (1) electric utility return is regulated by individual states whose regulatory philosophies are fairly similar and (2) utilities compete in a national market for capital. Since the deviation in financial risk between various utilities is relatively small, so is their interest cost for debt securities at any given time.

Considerable discussion surrounds the selection of appropriate "cost of capital" or "target return" rates to be used in evaluating investment alternatives. One point frequently raised is that these costs should represent conditions anticipated during the life of the project and not historic costs. Fortunately, for purpose of this study, the utility return on investment (the combined return on bonds and the equity of all classes

TABLE 20. 1960 AVERAGE PROPERTY TAX RATES (PERCENT) ON ALL TAXABLE PROPERTY(30)

FPC District I	
Maine	2.4
Vermont	2.1
New Hampshire	1.9
Massachusetts	2.4
Rhode Island	1.9
Connecticut	1.6
New York	2.1
New Jersey	2.3
Pennsylvania	1.3
Maryland	1.5
Delaware	0.7
Average	1.8

FPC District II	
West Virginia	0.9
Ohio	1.4
Michigan	1.8
Indiana	1.2
Kentucky	0.8
Average	1.2

FPC District III	
Virginia	0.9
North Carolina	0.8
South Carolina	0.8
Tennessee	1.0
Georgia	0.9
Alabama	0.5
Florida	1.1
Average	0.9

FPC District IV	
Wisconsin	1.9
Illinois	1.5
Minnesota	1.9
Iowa	1.2
Missouri	1.1
Average	1.5

FPC District V	
Kansas	1.4
Arkansas	0.6
Mississippi	0.7
Louisiana	0.8
Oklahoma	0.9
Texas	1.0
New Mexico	0.6
Average	0.9

FPC District VI	
North Dakota	1.3
South Dakota	1.4
Nebraska	1.4
Wyoming	1.0
Colorado	1.4
Average	1.3

FPC District VII	
Montana	1.1
Idaho	1.0
Utah	1.1
Washington	0.9
Oregon	1.6
Average	1.2

FPC District VIII	
California	1.4
Nevada	0.9
Arizona	1.0
Average	1.1

United States Average	1.4

of stock) is regulated by the individual states. Not only are these procedures somewhat similar among states, but, in many cases, legal proceedings are required to alter the allowable return. The latter procedure tends to make changes in rates and utility returns far less volatile than swings in the financial markets.

The Federal Power Commission provides a tabulation of rates of return for all electric utilities, calculated on a consistent basis, in its annual statistical summary.(31) It must be emphasized that this "rate of return" is different in a financial sense than the one usually considered because it includes the return on debt as well as equity components. Figure shows the median United States return from 1961 through 1966. In 1966, 75.9 percent of all U. S. electric utilities earned returns of between 6.00 percent and 8.99 percent; thus, the disperison around the 7.44 percent median is fairly small. Although this rate of return has been steadily rising for the past 5 years, the rate of increase appears to be leveling off.

The computational procedure outlined in the FPC summary(31) was applied to the composite income statement and balance sheet of all United States electric utilities for 1966 which are summarized in the same publication. These calculations produced an average return of 7.03 percent. The fact that the average return is 0.945 times the median indicates a skewed distribution of returns, and we have assumed the distribution to retain the same shape every year. Thus, in any year, the average return should approximate 0.945 times the median return published by the FPC. This estimation is applied to historical data in Figure 33.

Sample calculations are summarized in Table 21. These are based upon both the current average 7.0 percent return figure and a 7.5 percent return in order to reflect anticipated future conditions. The average interest rate paid by all electric utilities on their debt is included in this return and can be calculated from the summarized financial statements in the FPC statistical summary. This rate was 3.67 percent in 1966. Should the utilities continue to pay 6 percent or more for new long-term-debt securities, this average interest cost should rise substantially. The 7.5 percent return figure assumes an average interest cost approaching 5 percent; however, the earnings rate on equity is assumed to have remained the same in this calculation. In the long run, the equity return rate would also rise in order to maintain a spread representative of the different risks inherent between these two types of securities. For purposes of reviewing the appropriateness of the return component of the carrying charges calculated in this report, however, one need only check the trend of median utility returns published in future FPC statistical summaries, apply the appropriate average to median ratio (0.945), and consider current trends in the financial markets.

Because interest expenses are deductible from State and Federal income taxes it is necessary to know how the total return is divided between return on debt and equity. Actually, the FPC calculated return includes a third relatively small factor, tax credits. The distribution for a 7.0 percent return is estimated from the composite financial statements in the FPC statistical summary(31) and is shown in Table 22. The estimated distribution for a 7.5 percent return (assuming the added 0.5 percent is entirely attributable to higher interest costs) is also indicated.

Other assumptions made in generating the carrying charges were the use of sinking fund depreciation for making the investment decision and double-declining balance depreciation for tax purposes. The sinking-fund discount rate was assumed to be the same as the cost of money. A United States' utility average debt-equity ratio in 1966 of 0.5226 to

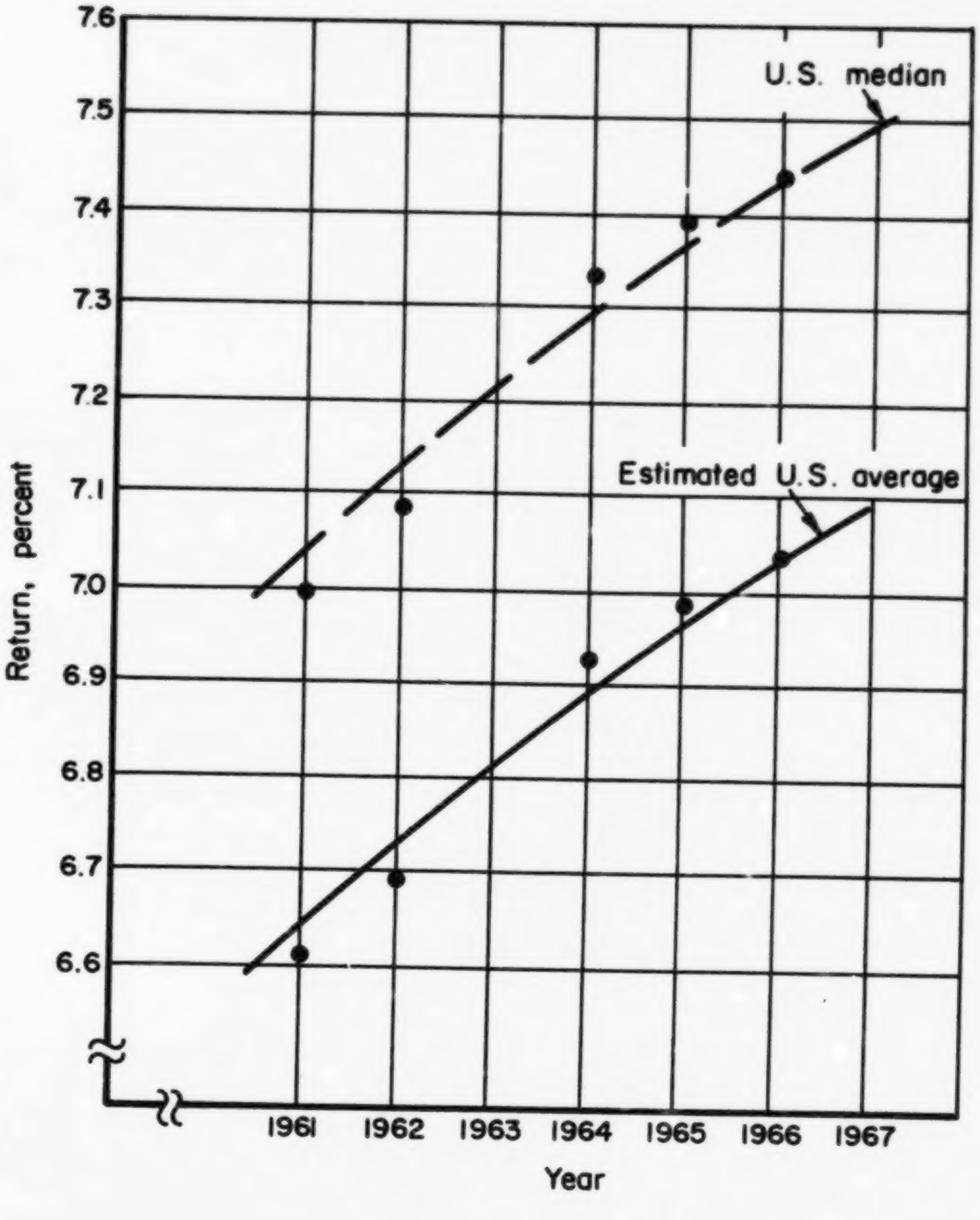


FIGURE 33. MEDIAN AND ESTIMATED AVERAGE U. S. ELECTRIC UTILITY RETURNS (AFTER TAXES AND DEPRECIATION BUT BEFORE INTEREST) AS A PERCENT OF NET PLANT INVESTMENT(31)

TABLE 21. ESTIMATED LEVELLIZED ANNUAL CARRYING CHARGES (PERCENT) FOR VARIOUS RETURN RATES AND PLANNING PERIODS

	7% Return – 20 Years					7-1/2 % Return – 20 Years				
FPC Dist.	Return and Depr.	Fed. Inc. Tax	State Inc. Tax	Rev. Taxes	Total	Return and Depr.	Fed. Inc. Tax	State Inc. Tax	Rev. Taxes	Total
I	9.44	3.33	0.33	0.89	13.99	9.81	3.12	0.31	0.88	14.12
II	"	"	0.07	0.20	13.04	"	"	0.06	0.19	13.18
III	"	"	0.25	0.93	13.95	"	"	0.23	0.91	14.07
IV	"	"	0.13	0.26	13.16	"	"	0.12	0.26	13.31
V	"	"	0.14	0.23	13.14	"	"	0.13	0.22	13.28
VI	"	"	0.10	0.00	12.87	"	"	0.09	0.00	13.02
VII	"	"	0.25	0.60	13.62	"	"	0.24	0.59	13.76
VIII	"	"	0.22	0.03	13.02	"	"	0.21	0.03	13.17
U.S. Avg.	9.44	3.33	0.20	0.49	13.46	9.81	3.12	0.19	0.48	13.60

	7% Return – 30 Years					7-1/2 % Return – 30 Years				
FPC Dist.	Return and Depr.	Fed. Inc. Tax	State Inc. Tax	Rev. Taxes	Total	Return and Depr.	Fed. Inc. Tax	State Inc. Tax	Rev. Taxes	Total
I	8.06	2.10	0.21	0.82	11.19	8.47	1.88	0.18	0.80	11.33
II	"	"	0.04	0.18	10.38	"	"	0.04	0.18	10.57
III	"	"	0.15	0.85	11.16	"	"	0.14	0.33	11.32
IV	"	"	0.08	0.24	10.48	"	"	0.07	0.24	10.66
V	"	"	0.09	0.21	10.46	"	"	0.08	0.21	10.64
VI	"	"	0.06	0.00	10.22	"	"	0.06	0.00	10.41
VII	"	"	0.16	0.55	10.87	"	"	0.14	0.54	11.03
VIII	"	"	0.14	0.03	10.33	"	"	0.12	0.03	10.50
U.S. Avg.	8.06	2.10	0.13	0.45	10.74	8.47	1.88	0.11	0.44	10.90

TABLE 22. ESTIMATED PERCENT DISTRIBUTION OF U. S. AVERAGE ELECTRIC UTILITY RETURNS AFTER TAXES BUT BEFORE INTEREST

	1966 Averages 7.0 Percent Return	Estimated for 7.5 Percent Return[a]
Interest	27.8%	33.2%
Equity	69.5%	64.3%
Tax Credits	2.7%	2.5%

(a) Assumes that all of increased return is attributed to increased interest rates.

0.4774, calculated from the FPC statistical summary,(31) was used. Furthermore, interest costs on long-term debt were based upon the 1966, 3.67 percent utility average. Federal income tax calculations included the 10 percent surcharge, and a 52.8 percent effective rate was employed.

State income tax rates and gross receipts rates vary widely; indeed, some states have no form of corporate income tax or special revenue taxes on utilities. Effective rates for the year 1966 were obtained from The State Tax Handbook(32) and are tabulated in Table 23. These rates, in turn, were averaged for the group of states in each FPC district, and the average rate for each district is also shown in Table 23. In certain states, Federal Income Tax is deductible from the state tax. In these cases, the published state rate has been reduced by a factor representing the deduction, so that the percentage shown is the effective rate on net income before income taxes. In other states a tax is imposed on each kwhr of electricity generated. On the basis of United States' averages, this generation tax has been converted to a fraction of gross receipts and is included in the gross receipts tax rate in Table 23.

Carrying charges computed on the basis of these assumptions and stated as a constant annual percentage of the original investment cost are summarized in Table 21. These carrying charges have been calculated both for a 7.0 and 7.5 percent return and consider a 20- and 30-year planning period. Data derived from the FPC statistical summary and all other historic cost data would currently reflect carrying charges at 7.0 percent and 30 years. Utility rates are normally based upon historical costs; thus, this combination of return and equipment life might represent the impact of an investment decision on the cost of electricity as generated.

For the purposes of planning, however, the utility may wish to minimize the risks attributable to uncertainty and would evaluate the investment over a shorter, 20-year period. Furthermore, it might apply an anticipated return rather than historic figure. Thus, for the purpose of simulating a utility investment decision, carrying charges based upon a 20-year life and 7.5 percent return might be more realistic.

For a given rate of return and planning period, it has been assumed that these two factors will not vary among the eight FPC Districts. Thus, although state income taxes and gross revenue taxes do vary from one location to another, these are all deductions before net income. Net income is assumed constant; therefore, the Federal Income Tax charge will not show a regional variation.

TABLE 23. 1966 EFFECTIVE STATE INCOME TAX RATES, GROSS RECEIPTS, TAX RATES, AND TAXES (PERCENT) ON GENERATION OF ELECTRICITY CONVERTED TO AN EQUIVALENT GROSS-RECEIPTS BASIS(32)

	S. Inc.	Gr. Recpts.
FPC District I		
Maine	–	–
Vermont	5.0	3.1(a)
New Hampshire	9.0	–
Massachusetts	6.8	–
Rhode Island	6.0	2.5
Connecticut	5.3	4.0
New York	5.5	2.5
New Jersey	3.3	14.6
Pennsylvania	6.0	1.4
Maryland	5.0	2.0
Delaware	5.0	0.1
Average	5.2	2.7
FPC District II		
West Virginia	–	–
Ohio	–	3.0
Michigan	–	0.2
Indiana	2.0	–
Kentucky	3.3(b)	–
Average	1.1	0.6
FPC District III		
Virginia	5.0	3.5
North Carolina	6.0	6.0
South Carolina	5.0	3.4(a)
Tennessee	4.0	3.5
Georgia	5.0	–
Alabama	2.4(b)	2.9(a)
Florida	–	0.3
Average	3.9	2.8
FPC District IV		
Wisconsin	3.3(b)	–
Illinois	–	4.1
Minnesota	4.4(b)	–
Iowa	1.9(b)	–
Missouri	0.9(b)	–
Average	2.1	0.8
FPC District V		
Kansas	2.1(b)	–
Arkansas	5.0	0.4
Mississippi	3.0	–
Louisiana	1.9(b)	2.0
Oklahoma	1.9(b)	–
Texas	–	2.0
New Mexico	1.4(b)	0.5
Average	2.2	0.7
FPC District VI		
North Dakota	2.8(b)	–
South Dakota	–	–
Nebraska	–	–
Wyoming	–	–
Colorado	5.0	0.2
Average	1.6	0.0
FPC District VII		
Montana	5.3	1.3
Idaho	6.0	3.1(a)
Utah	2.8(b)	0.3
Washington	–	3.8
Oregon	6.0	0.3
Average	4.0	1.8
FPC District VIII		
California	5.5	–
Nevada	2.0	–
Arizona	3.1(b)	0.2
Average	3.5	0.1
United States Average	3.2	1.5

(a) Includes tax on generation.

(b) Published rate modified to reflect deductibility of Federal Income Tax.

The relative sensitivity of these carrying charges is illustrated by the four cases in Table 21. For a given evaluation period, there is little variation in the overall carrying charge as a result of changing costs of money, if the change is primarily in the interest cost on debt. In the long run, one would expect the return on equity to rise also and this would ultimately result in substantially increased carrying charges since all the tax components would then also increase. Although not shown, one could anticipate a high degree of sensitivity to a change in income tax rate if a given return after taxes is to be maintained. Finally, the anticipated sensitivity to changes in depreciation or planning period is shown by comparing the examples for 20 to 30 years for a given rate of return.

It should be pointed out that in the cost model and in the treatment of annual carrying charges, the investment, operating costs, etc., of the SO_2-control process have been considered in the same light as any other component of the power station. Under current laws and regulations, there appears to be some question as to the validity of this approach. It is not appropriate to argue this point here. But, if some other method of treatment proves to be necessary, only minor modifications of the model structure will be needed.

Insurance Costs

Insurance costs for generating facilities consist primarily of two components, property and liability insurance. The cost is divided nearly equally between these two types and the total cost varies in proportion to the size and value of a facility. The cost, therefore, may be stated as a percentage of plant first cost, and this percentage will be nearly uniform for all sizes of conventional steam plants.

An early impediment to commercial development of nuclear power was the question of unlimited liability in the event of an accident. Although the probability of such a catastrophe is minute, without some actuarial experience, insurance companies were unwilling to provide insurance, and without some legal limitation on their liability, potential users were unwilling to risk developmental investment. The Price-Anderson Act of 1957 provided this statutory limitation, and it further authorized the AEC to indemnify parties held liable for damages incurred as a result of a nuclear incident. AEC coverage is extended only for amounts in excess of $74 million and up to the statutory limit. This, in effect, limits the amount of privately placed liability-insurance coverage required for a given nuclear facility to $74 million and tends to lower the cost of insurance coverage, stated as a percent of first cost, as the size of nuclear plants increases. Nevertheless, insurance costs are considerably higher on a nuclear plant than on a comparable sized fossil-fuel-fired installation because of the greater potential liability and the larger investment required per Mw(e) of capacity.

Annual insurance costs expressed as a percentage of unit first cost were computed from a number of sources and plotted in Figure 34. These sources include data acquired from field interviews, the National Power Survey,(33) and an analysis done by S. M. Stoller Associates, a nuclear consultant, for an A. D. Little report on the "Future Market for Utility Coal in New England".(34) Trend lines have been estimated and are suitable for use in the model; however, it would be desirable to develop a larger data base, in particular, to more accurately estimate nuclear insurance costs.

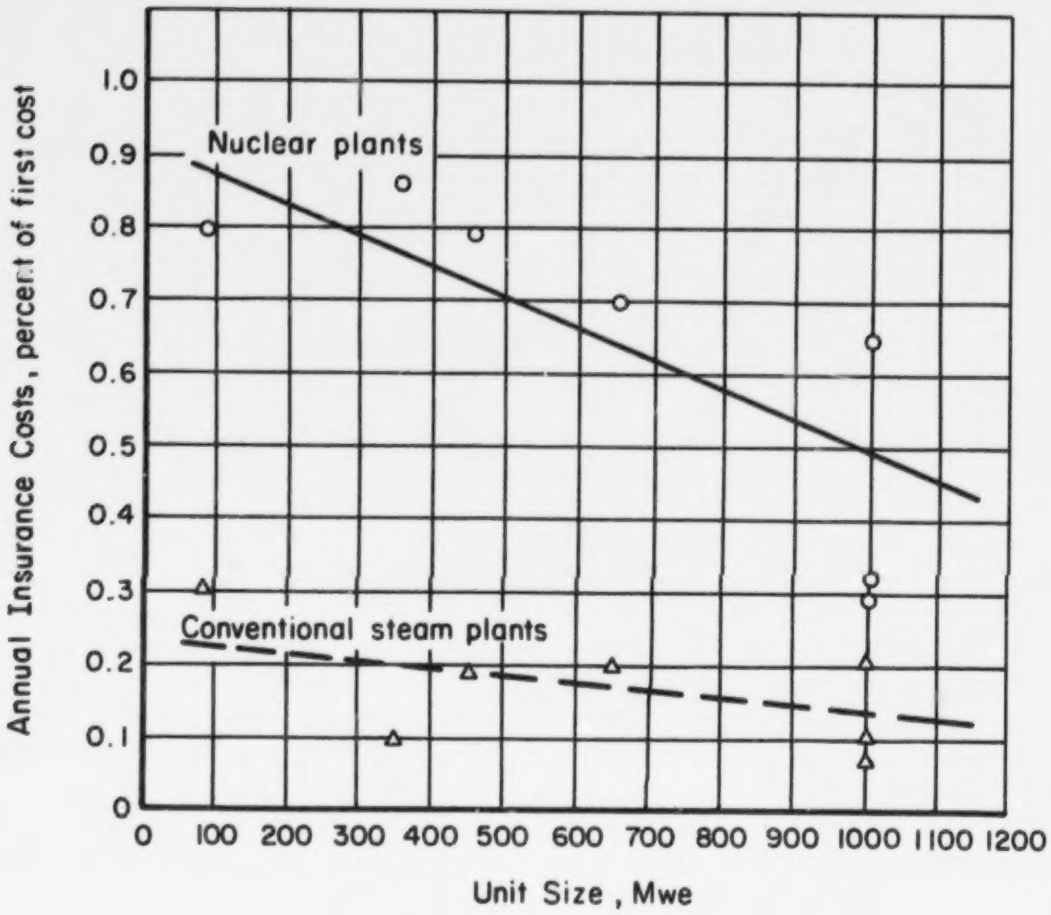


FIGURE 34. ANNUAL PROPERTY AND LIABILITY INSURANCE COSTS FOR A GENERATING UNIT AS A FUNCTION OF UNIT SIZE(33, 34)

NUCLEAR-POWER GENERATION

Nearly half of all the new electrical-generation capacity planned between now and 1974 will use a nuclear energy source. Although a variety of subjective considerations (such as possible future pollution-control regulations) may have had an impact upon these decisions, the primary determinant was undoubtedly anticipated economic gain. Although some question is still raised about future supplies of fissionable material, the overriding cost component in any nuclear-power-plant evaluation is the capital cost of the facility. On an annual basis, carrying charges are typically one-half of the total cost of nuclear power generation.

Unfortunately, these investment costs have fluctuated widely and have trended sharply upward in the recent past. Since there is a long lead time (at least 6 years) between announced construction and the in-service date of a nuclear plant, these higher costs will be reflected in stations coming on line after 1974.

For the purpose of this study, nuclear generation may be considered as an alternative to controlling the SO_2 emissions from a fossil-fuel-fired station. Therefore, primary interest is in the anticipated costs of nuclear plants being planned at any given point in time. With the nuclear cost picture being so volatile, historic cost data are not very useful for this purpose. Furthermore, only a small number of nuclear stations are currently in operation, and historic nuclear cost data are not available in abundance. Cost data for nuclear facilities are tabulated in the FPC's publication Steam-Electric Plant Construction Cost and Annual Production Expenses(3); however, the facilities included to date are smaller than 300 Mw, and it will be several years before enough larger nuclear plants are in operation to make this a useful data source.

TABLE 24. NUCLEAR-GENERATION-COST ESTIMATES DERIVED FROM UTILITY INTERVIEWS

Unit Name	Ft. St. Vrain[a]	San Orofre	Diablo Canyon No. 2	Pilgrim No. 1	Browns Ferry Nos. 1 and 2	Indian Point No. 2	Indian Point No. 3
Utility	P. S. of Colo.	S. Calif. Ed.	Pac. G. & E.	Bost. Ed.	TVA	Cons.	Ed.
Scheduled in Service	1972	1968	1972	1971	1970	1969	1971
Size, Mw(e) net	350	430	1060	625	1063[b]	873	965
First Cost, $/kw	154	202	149	192	117	100	160
Est. Plant Factor, percent	83.5		80.0	91.0	85.0		
Fuel Cost, mills/kwhr	1.63		1.89		1.26[c]	1.62	1.76
O. & M., mill/kwhr	0.46		.09[b]	0.40	0.19		
Insurance, mill/kwhr	0.18		.06		.04		
Substation O. & M, mill/kwhr	.02		.01		.01		
Subtotal, mills/kwhr	2.29		2.05		1.50		
Utility Fixed Charges, mills/kwhr	2.48		2.55		0.89[c]		
Total, mills/kwhr	4.77		4.60		2.39[c]		

(a) High-temperature gas-cooled reactor (some costs subsidized).

(b) Personnel may be shared with Unit No. 1.

(c) TVA's low carrying charges make these components seem disproportionately small.

Table 24 is a listing of costs made available by utilities visited in the course of this study. The data are useful as indications of relative costs; however, the data base is too small to allow meaningful aggregation. Table 25 is a tabulation of nuclear plants for which construction plans have been announced. The estimated first costs in terms of $/kw have been grouped by unit size and by year of planned installation. This is shown in Figure 35. Not only does the installed cost/kw rise sharply as unit size decreases, but a sharp annual upward cost trend is evident for all sizes. Figure 36 shows estimates of installed costs by unit size for all types of steam-generating facilities, including nuclear, for the year 1974.

The estimation of nuclear fuel costs requires a financial model of its own since the fuel is purchased (or leased) a year or more before the plant goes into operation. It is then treated, used, repositioned in the core, processed with credits accruing to recovered plutonium, and then reused. A typical cycle as just described may last from 3 to 5 years. Thus, the largest portion of these costs are carrying charges. How this investment is distributed over the energy generated is dependent upon plant capacity factor, cost of money, taxes, and other items. Because analysis of the costs associated with nuclear-fuel management is a science in itself, fuel costs as estimated by utilities should be used for making the necessary predictions. This assumes that the installations' operating patterns and financial costs are similar enough so that serious error is not introduced by this aggregation. Figure 37 is a 1965 estimate of the trend in nuclear fuel costs; however, recent experience suggests that this trend is not dropping as rapidly as indicated.

Estimates of operating and maintenance expenses for different sizes of nuclear plants for both 1970 and 1975 are shown in Table 26. Table 27 shows the estimated total cost of generation in mills/kwhr for three nuclear plants that are approaching the operating stage. These costs are broken down into carrying charges, fuel costs, and other. The costs on Brown's Ferry have been adjusted from TVA's to a private utility's financial costs. The data in Figure 37 and Table 26 seem to fit into the framework of the data in Table 27.

The data were combined to generate a sample calculation which might be representative of a nuclear facility being planned now for 1974 operation. These calculations are summarized in Table 28, and the prospects for nuclear generation are, on the whole, not so encouraging in the future as in the past. This picture is largely created by the sharply increasing first cost of these facilities, and for purposes of comparison, the same costs have been generated for typical installed costs of 1 year earlier. This results in overall generation costs in mills/kwhr that are 5 to 10 percent lower for facilities starting in 1973 than for those starting in 1974. Since many of the first costs quoted for plants scheduled for operation between 1970 and 1973 are as much as 30 percent less than the general 1974 cost levels, the rush to nuclear power in this period is understandable.

Thus, in expanding the data base of nuclear-generation costs in the immediate future, cost estimates of those facilities currently being planned should be relied upon. A report on nuclear-power-plant activity is published annually in Electrical World(35) and is a source for data of this type.

The staff of Electrical World is also maintaining a tabulation of all planned generating facilities. Appendix B shows the fossil-fuel and hydroelectric portions to

TABLE 25. NUCLEAR PLANTS UNDER CONSTRUCTION OR ANNOUNCED (35)

Owner [operator]	Station	Service date	Plant rating Mw(e) net	Reactor Mw(t)	Reactor mfr	Turbine mfr	Plant designer	Plant construction	Capital cost, $
1968									
Jersey Central P&L	Oyster Creek 1	4Q-68	515 [640]	1,600 [1,920]	GE	GE	Burns & Roe	Burns & Roe	NA
Dairyland Pwr Co-op	Lacrosse BWR	1968[15]	50	165	A-C	A-C	S&L	Maxon Const.	20,235,000
Niagara Mohawk Pwr	Nine Mile Point 1	4Q-68	500 [620]	1,538 [1,779]	GE	GE	Owner	S&W	135,000,000
1969									
Commonwealth Edison	Dresden 2	1969	715 [809]	2,255 [2,527]	GE	GE	S&L	UE&C	80,000,000[8]
Consolidated Edison	Indian Point 2	2Q-69	873	2,758	West.	West.	UE&C	UE&C	NA
Northeast Utilities	Millstone 1	3Q-69	652.1	2,011	GE	GE	Ebasco	Ebasco	99,000,000
Rochester G&E	R. E. Ginna 1	2Q-69	420	1,300	West.	West.	Gilbert	Bechtel	74,000,000
1970									
Commonwealth Edison	Dresden 3	1970	715 [809]	2,255 [2,527]	GE	GE	S&L	UE&C	79,000,000[8]
Comm. Edison, Iowa-Ill.	Quad-Cities 1	1970	715 [809]	2,255 [2,527]	GE	GE	S&L	UE&C	80,000,000[1,5]
Tenn. Valley Authority	Browns Ferry 1	4Q-70	1,075 [1,129]	3,293 [3,440]	GE	GE	Owner	Owner	123,000,000[1]
Florida P&L	Turkey Point 3	2Q-70	688.5	2,202	West.	West.	Bechtel	Bechtel	133,000,000
Wisconsin-Michigan Power	Point Beach 1	2Q-70	454 (497)	1,396 [1,518]	West.	West.	Bechtel	Bechtel	65,500,000
Carolina P&L	Robinson 2	2Q-70	663	2,094	West.	West.	Ebasco	Ebasco	76,200,000
Northern States Power	Monticello 1	2Q-70	472 [545]	1,469 [1,674]	GE	GE	Bechtel	Bechtel	75,000,000
Consumers Power	Palisades	2Q-70	700 [821]	2,200 [2,640]	Comb.	West.	Bechtel	Bechtel	104,000,000[8,1]
1971									
Duke Power	Oconee 1	2Q-71	841 [886]	2,468 [2,584]	B&W	GE	Owner	Owner	88,500,000[1]
Comm. Edison, Iowa-Ill.	Quad-Cities 2	1971	715 [809]	2,255 [2,527]	GE	GE	S&L	UE&C	80,000,000[1,5]
Consolidated Edison	Indian Point 3	2Q-71	965	3,025	West.	West.	UE&C	UE&C	NA
Tenn. Valley Authority	Browns Ferry 2	4Q-71	1,075 [1,129]	3,293 [3,440]	GE	GE	Owner	Owner	123,500,000[1]
Florida P&L	Turkey Point 4	2Q-71	688.5	2,202	West.	West.	Bechtel	Bechtel	133,500,000
Wisconsin-Michigan Power	Point Beach 2	2Q-71	454 [497]	1,396 [1,518]	West.	West.	Bechtel	Bechtel	62,000,000
Philadelphia Elect. et al[9]	Peach Bottom 2	2Q-71	1,065	3,295	GE	GE	Bechtel	Bechtel	142,500,000[1]
Vermont Yankee Nuclear	Vermont Yankee	3Q-71	514 [540]	1,593 [1,665]	GE	GE	Ebasco	Ebasco	115,000,000
Omaha Public Power Dist.	Ft. Calhoun 1	2Q-71	457	1,420	Comb.	GE	Gibbs & Hill	Owner	71,600,000
Virginia E&P	Surry 1	1Q-71	780 [812]	2,441 [2,546]	West.	West.	S&W	S&W	127,630,000[1]
Boston Edison	Pilgrim 1	4Q-71	625 [654]	1,912 [1,998]	GE	GE	Bechtel	Bechtel	Note 17
Metropolitan Edison	Three Mile Island 1	2Q-71	810 [840]	2,452 [2,535]	B&W	GE	Gilbert	UE&C	129,000,000
Niagara Mohawk Power	Easton 1	4Q-71	750	2,381	GE	GE	Owner/S&W	S&W	NA
1972									
Duke Power	Oconee 2	2Q-72	841 [886]	2,468 [2,584]	B&W	GE	Owner	Owner	88,500,000[1]
Commonwealth Edison	Zion 1	1972	1,050 [1,100]	3,250 [3,391]	West.	West.	S&L	Owner	125,000,000[1,5]
Pacific G&E	Diablo 1	2Q-72	1,060	3,250	West.	West.	Owner	Owner	153,633,000
Consumers Public Pwr. Dist.	Cooper 1	2Q-72	778	2,381	GE	West.	Burns & Roe	Burns & Roe	130,000,000
Maine Yankee Atomic Pwr	Maine Yankee	2Q-72	830 [855]	2,560 [2,630]	Comb.	West.	S&W	S&W	131,000,000
Public Service E&G, et al[9]	Salem 1	1Q-72	1,050 [1,093]	3,250 [3,391]	West.	West.	Owner	UE&C	130,000,000[1]
Arkansas P&L	Russellville 1	4Q-72	850	2,568	B&W	West.	Bechtel	Bechtel	140,000,000
Wisconsin PS, et al[10]	Kewaunee 1	2Q-72	527	1,650	West.	West.	Pioneer	Pioneer	83,000,000
Tenn. Valley Authority	Browns Ferry 3	4Q-72	1,075 [1,129]	3,293 [3,440]	GE	GE	Owner	Owner	145,000,000
Public Service of Colo.	Fort St. Vrain	1Q-72	330	842	GGA	GE	S&L	Ebasco	52,000,000
Northern States Power	Prairie Island 1	2Q-72	530 [550]	1,650 [1,721.4]	West.	West.	Pioneer	Owner	93,300,000[1]
Virginia E&P	Surry 2	1Q-72	780 [812]	2,441 [2,546]	West.	West.	S&W	S&W	127,630,000[1]
Florida Power	Crystal River 3	2Q-72	855 [885][16]	2,452 [2,560]	B&W	West.	Gilbert	Owner	114,000,000[8,1]
Indiana & Michigan [AEP]	Cook 1	2Q-72	1,054 [1,093]	3,250 [3,391]	West.	GE	Owner	Owner	150,000,000[1]
1973									
Duke Power	Oconee 3	2Q-73	841 [886]	2,468 [2,584]	B&W	GE	Owner	Owner	101,000,000
Commonwealth Edison	Zion 2	1973	1,050 [1,100]	3,250 [3,391]	West.	West.	S&L	Owner	125,000,000[1,5]
Consolidated Edison	Undecided	2Q-73	1,115	3,293	GE	AEI	Owner	Undecided	NA
Sacramento MUD	Rancho Seco 1	2Q-73	800	2,452	B&W	West.	Bechtel	Undecided	142,530,000
Los Angeles, DWP	Malibu	2Q-73	462	1,473	West.	Undecided	Owner	Owner	92,500,000
Iowa Electric L&P	Duane Arnold	4Q-73	550	1,593	GE	GE	Comm. Assoc.	Undecided	100,000,000
Baltimore G&E	Calverts Cliffs 1	1Q-73	800 [865]	2,450 [2,700]	Comb.	GE	Bechtel	Bechtel	123,190,000
Georgia Power	Edwin I. Hatch 1	1973	800	2,436	GE	GE	Owner/Bechtel	Owner	150,000,000
Long Island Lighting	Shoreham 1	2Q-73	523 [553]	1,593 [1,665]	GE	GE	S&W	S&W	NA
New York State E&G	Bell Station 1	2Q-73	830	2,436	GE	GE	UE&C	UE&C	125,000,000[8]
Public Service E&G, et al[9]	Salem 2	1Q-73	1,050 [1,093]	3,250 [3,391]	West.	West.	Owner	UE&C	130,000,000[1]
Carolina P&L	Brunswick 1	2Q-73	820	2,436	GE	GE	UE&C	UE&C	127,200,000
Philadelphia Elec, et al[9]	Peach Bottom 3	2Q-73	1,065	3,295	GE	GE	Bechtel	Bechtel	142,500,000[1]
Jersey Central P&L	Oyster Creek 2	2Q-73	810 [920]	2,452 [2,772]	B&W	West.	Burns & Roe	Burns & Roe	NA
Duquesne Light, et al[4]	Beaver Valley 1	2Q-73	800	2,440	West.	West.	S&W	S&W	150,000,000
Indiana & Michigan [AEP]	Cook 2	2Q-73	1,028 [1,087]	3,250 [3,391]	West.	B-B	Owner	Owner	150,000,000[1]
1974									
Northeast Utilities	Millstone 2	2Q-74	828.2	2,560	Comb.	Undecided	Undecided	Undecided	NA
Toledo Edison, CEI	Undecided	4Q-74	800	Undecided	Undecided	Undecided	Undecided	Undecided	128,000,000
Baltimore G&E	Calverts Cliffs 2	1Q-74	800 [865]	2,450 [2,700]	Comb. Engr.	West.	Bechtel	Bechtel	107,190,000
Pacific G&E	Diablo 2	3Q-74	1,060	3,250	Undecided	Undecided	Owner	Owner	130,470,000
Carolina Power & Lt	Brunswick 2	2Q-74	820	2,436	GE	GE	UE&C	UE&C	136,000,000
Northern States Power	Prairie Island 2	2Q-74	530 [550]	1,650 [1,721]	West.	West.	Pioneer	Owner	93,300,000
Virginia E&P	North Anne 1	1Q-74	780 [812]	2,441 [2,546]	West.	West.	S&W	S&W	100,000,000[1,5]
So Cal Ed, San Diego	Bolsa Island 1	3Q-74	≈800	NA	Undecided	Eng. Elect.	Undecided	Undecided	NA
Consumers Power	Midland 1	2Q-74	≈600	≈2,440[20]	Undecided	Undecided	Bechtel	Bechtel	133,500,000[1,21]
Portland GE	Trojan	4Q-74	≈1,000	NA	Undecided	Undecided	—	—	160,000,000
1975									
Los Angeles, DWP	Bolsa Island 2	2Q-75	≈880[7]	≈3,300	Undecided	Eng. Elect.	Owner	Owner	204,980,000
Philadelphia Elect	Undecided	2Q-75	1,065	3,295	GE	GE	Undecided	Undecided	—
Consumers Power	Midland 2	1975	≈600	≈2,440[20]	Undecided	Undecided	Bechtel	Bechtel	133,500,000[1,21]
1977									
Philadelphia Elect.	Undecided	2Q-77	1,065	3,295	GE	GE	Undecided	Undecided	NA
Not Scheduled									
Consolidated Edison	Undecided	—	1,115	3,293	GE[5]	AEI[5]	Owner	Undecided	NA
Northern Indiana PS	Bailly 12	—	515[6]	—	GE[6]	—	—	—	—
Carolina P&L	Undecided	—	820	2,436	GE	GE	Undecided	Undecided	NA
Duquesne Light (AEC)	Shippingport	1957	150	505	West.	West.	Owner[19]	Burns & Roe[19]	72,300,000[20]
Commonwealth Edison	Dresden 1	1960	200	700	GE	GE	Bechtel	Bechtel	34,000,000[8]
Yankee Atomic Elect	Yankee Nuclear	1961	175	600	West.	West.	S&W	S&W	$238/kw
Consolidated Edison	Indian Point 1	1962	270	615	B&W	West.	Owner	Owner	NA
AEC [Rural Co-op Power]	Elk River	1962	20.8	58.2	A-C	Elliott	A-C	Maxon Const.	13,900,100
Saxton Nuclear Corp[14]	Saxton	1962	4.3	23.5 [35]	West.	West.	West.	—	6,500,000
Detroit Edison	Enrico Fermi	1963[15]	60.9 [150]	200 [400]	Comb.	A-C	APDA/Comm.	UEAC	71,200,000
Pacific G&E	Humboldt Bay 3	1963	65	240	GE	GE	Bechtel	Bechtel	24,300,000
Consumers Power	Big Rock Point	1963	75	240	GE	GE	Bechtel	Bechtel	26,100,000
AEC [Puerto Rico WRA]	Bonus	1964	17.3[16]	50[16]	Comb.	—	—	—	19,500,000[20]
Washington Public Pwr	Hanford	1966	800 [860][13]	4,000	Kaiser	GE	Burns & Roe[19]	Burns & Roe[19]	90,000,000[20]
Northern States Power	Pathfinder	1966	58.5	190	AC	AC	Pioneer	AC	29,200,000
Philadelphia Elect	Peach Bottom 1	1967	40	115	GGA	West.	Bechtel	Bechtel	25,000,000
Conn. Yankee Atomic	Haddam Neck	1Q-68	467 [567]	1,473 [1,825]	West.	West.	S&W	S&W	$266/kw
So Cal Ed, San Diego	San Onofre	1Q-68	430	1,347	West.	West.	Bechtel	Bechtel	88,548,000

[ ]—ratings in brackets are anticipated future upratings for stretch, relicensing, valves wide open, etc.

Abbreviations:

A-C—Allis Chalmers
AEI—Associated Electric Industries, Great Britain
APDA—Atomic Power Development Associates
B-B—Brown Boveri, Switzerland
B&W—Babcock & Wilcox
Comb.—Combustion Engineering
Comm.—Commonwealth Associates
GAI—Gilbert Associates Inc.
GE—General Electric
GGA—Gulf General Atomic
Gibbs & Hill—Gibbs, Hill, Durham and Richardson
NA—not available
Pioneer—Pioneer Service & Engr.
S&L—Sargent & Lundy
S&W—Stone & Webster Engr.
UE&C—United Engineers & Constructors
West.—Westinghouse Electric

Notes to tabulation:

[1] Half of total cost for two units
[2] Excludes $15 million for research & development
[3] Excludes indirect costs
[4] Jointly owned by Duquesne Light, Ohio Edison, and Penn. Pwr
[5] Optional
[6] Plant delayed
[7] Includes 80 Mw(e) obtained from Metropolitan Water District turbine
[8] Preliminary estimate
[9] Jointly owned by Public Service E&G, Phila Elect, Atlantic City Elec, and Delmarva P&L
[10] Jointly owned by Wisconsin PS, Wisconsin P&L, and Madison G&E
[11] Includes reservoir, dam and site development for ultimate 4,000 Mw
[12] Now under startup tests (3/29/68) report reaching 40 Mw(t)
[13] Data is for two unit turbine plant only—AEC owns reactor
[14] Stockholders: Jersey Central P&L, New Jersey P&L, Metro Edison, and Penelec
[15] Criticality date
[16] Plant gross output
[17] Data submitted to AEC: Total location costs $85,200,000; other costs $23,800,000; interest $[illegible],000,000
[18] Data from EW June 14, 1965
[19] For turbine plant only (S&W/West. designed reactor plant, Dravo was constructor)
[20] Includes capacity for steam supplied off-site
[21] Excludes land costs

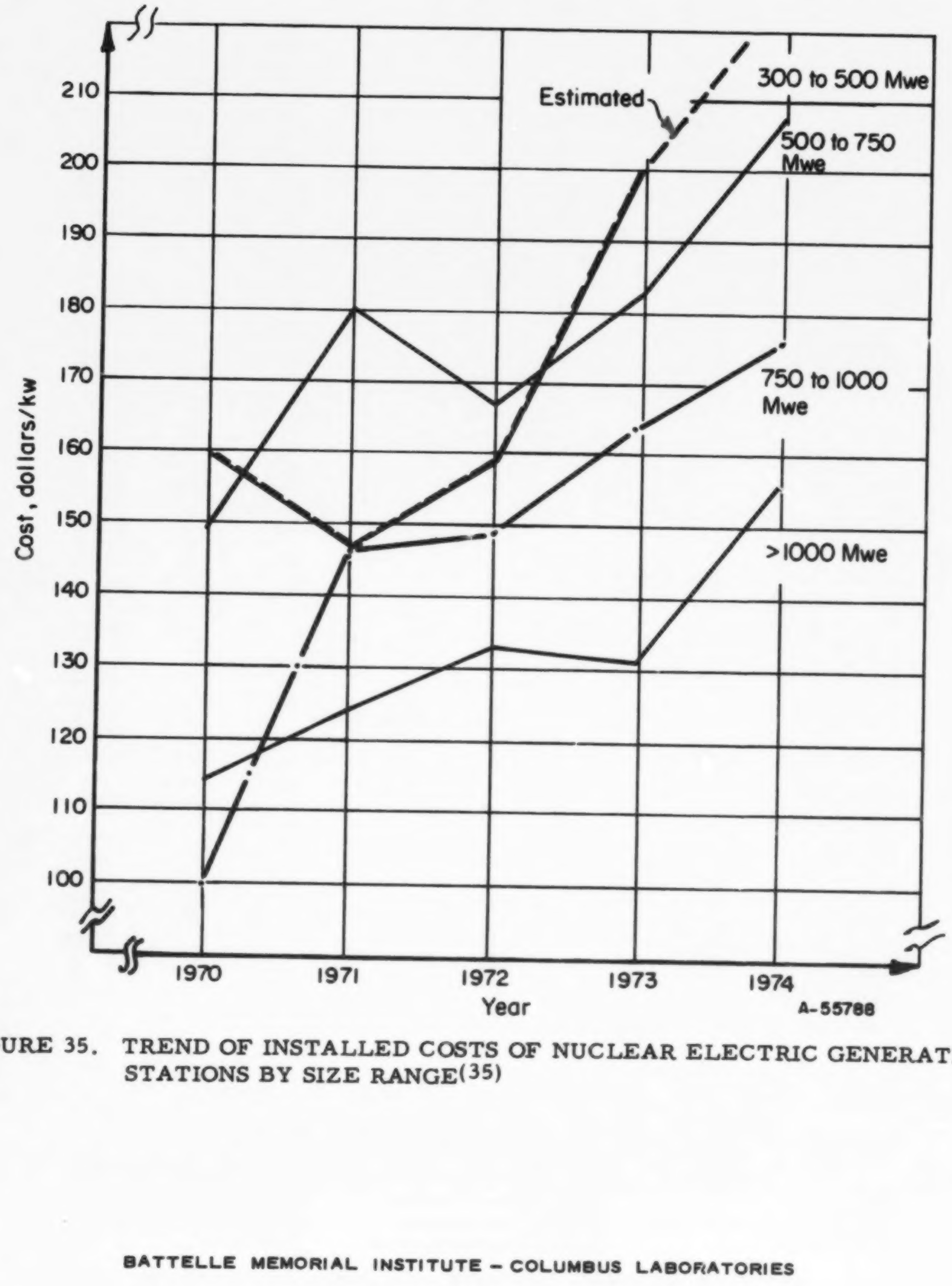


FIGURE 35. TREND OF INSTALLED COSTS OF NUCLEAR ELECTRIC GENERATION STATIONS BY SIZE RANGE(35)

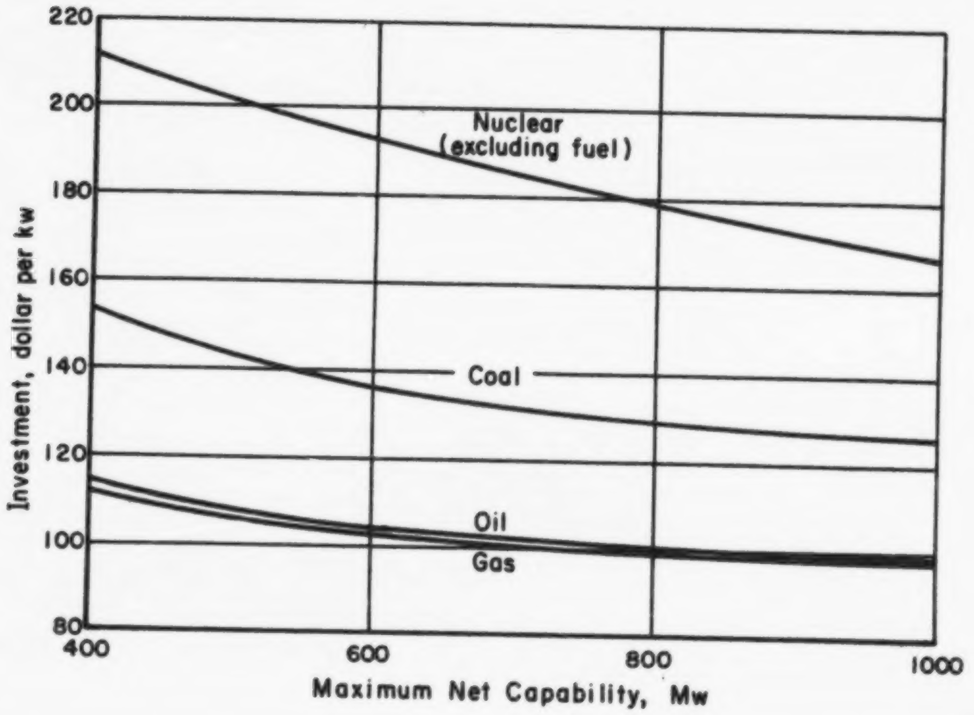


FIGURE 36. CAPITAL INVESTMENT AVERAGE SITE AND LABOR CONDITIONS 1974 OPERATION(15)

First Unit – New Site

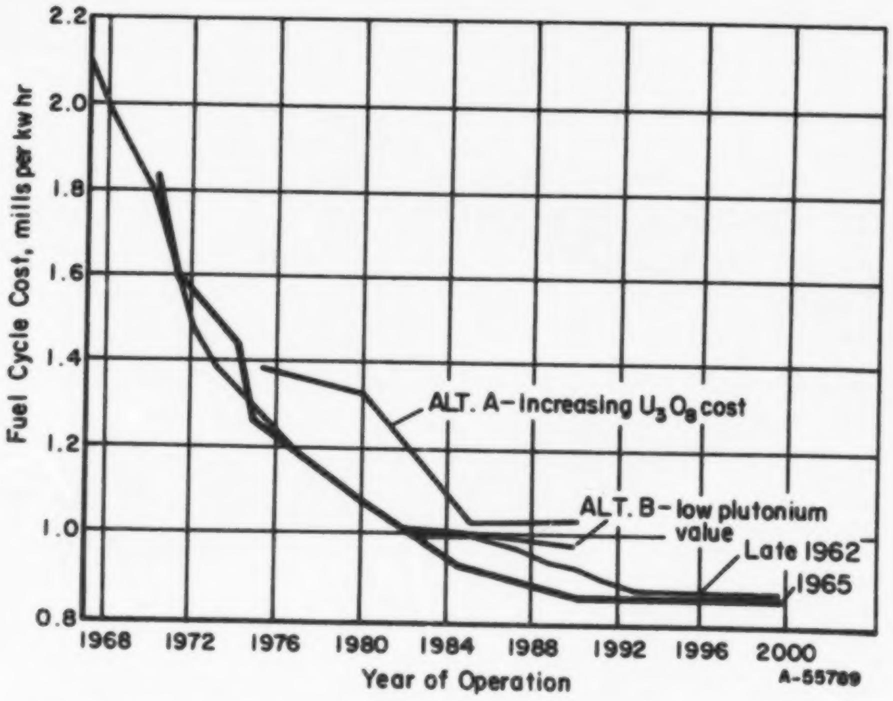


FIGURE 37. NUCLEAR FUEL CYCLE COST FORECASTS(36)

supplement the information for nuclear facilities shown in Table 25. It is expected that this information will be updated regularly. On the other hand, as soon as some operational experience is gained on the larger nuclear stations, fuel costs and operation and maintenance expenses should be less volatile, and they will be available annually in the FPC's report on steam-electric generation facilities(3) in the FPC accounting format.

TABLE 26. ESTIMATED NUCLEAR OPERATING, MAINTENANCE AND INSURANCE COSTS(37)

(Mills/Kwhr)

Year of Startup	1970			1975		
Electrical Power Output, net Mw	450	650	1000	450	650	1000
O&M	0.40	0.31	0.25	0.30	0.24	0.19
Insurance	0.21	0.16	0.13	0.15	0.12	0.10
Total	0.61	0.47	0.38	0.45	0.36	0.29

TABLE 27. APPROXIMATE GENERATING COSTS EXCLUDING LONG-RANGE ESCALATION(38)

(Mills/Kwhr)

	Plant	Fuel	Other	Total
1962-3 Cost Outlook Based on –				
Oyster Creek (Nuclear)	2.0	1.8	0.6	4.4
Comparable Coal Plant	1.9	1.9	0.6	4.4
1966 Cost Outlook Based on –				
Brown's Ferry (Nuclear)	2.1	1.6	0.4	4.1
Comparable Coal Plant	2.0	2.0	0.5	4.5
1967 Cost Outlook Based on –				
Diablo Canyon (Nuclear)	2.6	1.7	0.4	4.7
Comparable Coal Plant	2.3	2.1	0.5	4.9

Note: All figures adjusted to comparable basis.

TABLE 28. ESTIMATES OF NUCLEAR ELECTRIC-POWER-GENERATION UNIT COSTS FOR A PLANT STARTING OPERATION AFTER 1974 – 80 PERCENT ASSUMED PLANT FACTOR

(U. S. Average Figures)

Plant Size, Mw(e) net	400	600	800	1000
Installed Cost, $/kw	212	193	178	166
Carrying Charges at 10.74% (30 Years/at 7%), mills/kwhr	3.26	2.96	2.73	2.55
Property Taxes at 1.4%, mills/kwhr	0.43	0.39	0.36	0.34
Fuel, mills/kwhr	1.70	1.70	1.70	1.70
O. & M., mills/kwhr	0.35	0.31	0.28	0.22
Insurance, mills/kwhr	0.18	0.16	0.14	0.11
Total, mills/kwhr	5.92	5.52	5.21	4.92
Comparison with 1973 First-Cost Levels:				
Installed Cost, $/kw	200	182	164	132
Carrying Charges and Property Taxes, mills/kwhr	3.47	3.16	2.84	2.29
Total, mills/kwhr	5.70	5.33	4.96	4.32

EXAMPLES OF APPLICATION OF COST MODEL

This section contains a group of figures and a group of tables illustrating the use of the cost model and its associated data bank. The figures contain the model forms used and the solution for the selected situation. The tables summarize the results which have been computed for a number of situations believed to be of interest and are illustrative of the variety of situations that may be explored with the model.

Detailed Example

The example (Figures 38 through 43) for the Cook Plant, St. Joseph, Michigan, illustrates the use of the model forms for the power plant without SO_2 control and with the alkalized-alumina process installed.

This example illustrates some of the simplifications that can be resorted to in a "first-cut" analysis. For example, although the generating units are started 1 year apart, the analyst assumed that this was not of great significance since a 20-year period was being examined. Also, although the load factor was assumed to be decreasing from an initial 80 percent to 40 percent by the end of the planning period, it was decided that the average (60 percent) would be used to obtain the required totals for the planning period, since year-to-year variations were not considered of importance in this particular analysis. If this simplification could not be used, then all columns in the lines used would have been filled.

Form S, Summary of Results of Analysis (Figure 39), that follows shows that in this case, the incremental cost for SO_2-control using the alkalized-alumina process is 0.37 mill/kwhr after allowing for credits for sulfur produced. Also, this incremental cost is equivalent to $41.60 for each long ton of sulfur not allowed to enter the atmosphere as SO_2. Note that in this particular case the net energy available for distribution was taken as equal to that generated. This approach was used because the SO_2-control process and by-product-plant recurring costs already included a charge for electrical-energy requirements; also, the heat rate used was for the net output of the power plant, so energy consumption in the power plant was not considered. Since the nonrecurring and recurring costs for the SO_2-control equipment and by-product plant were combined in the type of estimate made, they are not shown separately in Form NR, Plant Construction and Start-Up Costs, and Form R, Recurring Cost Summary.

Results of Specific-Service-Area Analyses

The model has been used to analyze a number of situations for service areas which are believed of considerable interest and illustrative of the results which can be obtained through application of the model. The results presented here are suggested as providing insight concerning the ultimate problem being faced. This ultimate problem is one of planning research and development programs so that greatest efficacy can be achieved at the earliest time in the control of SO_2 emissions.

As in the previous two detailed examples, the data used for computation have been obtained from the sections of this report covering the recommended data on cost

Power Plant Identification: Cook

Location: St. Joseph, Mich. Service Area: Northern Indiana

Year of Start of Construction: ____

Generating Unit No.	Nameplate Capacity, megawatts	First Year of Operation
1	1041	1972*
2	1041	1973*

Type of Fuel	Fraction of Time Each Type Used
Coal	1.0
Oil	
Gas	

Planning Period Considered: 1973 Through 1992

Capacity Factor, %, Average: 60 *

SO_2 Control Processes Considered: Alkalized Alumina

Permissible SO_2 Concentration Used in Analysis: 200 ppm

Sulfur Removal: 90 %

Forms Used For Analysis (list by Form and Analysis Identification No.)

NR	E	FC	R	S	

Notes: * Both units assumed to start operation in 1973 for purposes of analysis.

*If the capacity factor varies during planning period, show on Form E.

Analysis Identification: BCL-1A

Date Prepared: 10/15/68

Analyst: HEC/RES/AWL/BLF

FIGURE 38. FORM A – ANALYSIS IDENTIFICATION AND GENERAL POWER-PLANT DATA

Line No.	Item	Units	Entry Source*	Without SO_2 Control	←SO_2-Control Options Considered→			
					Alkalized Alumina			
1	Total Nonrecurring Cost	Million $	Form NR	270	290			
2	Nameplate Generating Capacity	Megawatts	Form A	2082	2082			
3	Dollars/Kw	$/Kw	[(1)/(2)] x 10^3	130	139			
4	Total Recurring Costs**	Million $	Form R	679.0	708.0			
5	Total Annualized Nonrecurring Costs**	Million $	(1) x (%) x 0.2	726.8	780.7			
6	Total Cost	Million $	(4) + (5)	1405.8	1488.7			
7	Total Energy for Distribution	10^9 kwhr	Form E	219.6	219.6			
8	Cost/Energy	Mills/kwhr	(6) ÷ (7)	6.40	6.77			
9	Incremental Cost for SO_2 Control	Mills/kwhr	(8)***		0.37			
10	Total Sulfur Content of Fuel	10^3 long tons	Forms FC or FO	2210	2210			
11	Total Sulfur Removed	10^3 long tons	Process Analysis		1989			
12	Net Cost/Ton of Sulfur Removed	$/long ton	See Instructions		41.60			

*Numbers in parentheses refer to line number of form.

**Show percent of nonrecurring cost used for annualization 13.46.

***Subtract line (8) value in "Without SO_2 Control" column from appropriate column.

Notes:

Analysis Identification BCL-1A
Date Prepared 10/18/68
Analyst HEC/AWL/BLF

FIGURE 39. FORM S – SUMMARY OF RESULTS OF ANALYSIS

Item	FPC Account No.	(1)	(2)	Cost, millions of dollars
Land and Land Rights	310			
Structures and Improvements	311			
Boiler-Plant Equipment	312			
Engines	313			
Turbogenerator Units	314			
Accessory Electrical Equipment	315			
Miscellaneous Power Plant Equip.	316			
Power Plant Subtotal				270
Transmission-Facilities Construction Cost				0
SO_2-Control-Process Equipment				
By-Product Plant				
SO_2 Control Process and By-Product Plant Subtotal				20
Start-Up Costs				
Other (Specify)				
TOTAL				290

(1) Indicate number of power generating units considered where appropriate.

(2) Check in this column if cost includes consideration of modifications required for SO_2 control process.

Notes:

Analysis Identification BCL-1A

Date Prepared 10/15/68

Analyst HEC/RES/AWL/BLF

FIGURE 40. FORM NR – PLANT-CONSTRUCTION AND START-UP COSTS

Energy Generated

Line No.	Item	Units	Entry Source*	1973	74	75	76	77	78	79	80	81	82	83	84	85	86	87	88	89	90	91	92	Total
1	Nameplate Capacity	Megawatts	Form A	2082	→																			
2	Capacity Factor	Percent	Form A	80		(Use average value of 60 for planning period)																	40	
3	Energy Generated	Billion kwhr	$8.766 \times 10^{-5} \times (1) \times (2)$	14.64		(Use average value of 10.98 for planning period)																	7.32	219.6

Energy for SO_2 Control Equipment and By-Product Plant

Line No.	Item	Units	Entry Source*	1973	74	75	76	77	78	79	80	81	82	83	84	85	86	87	88	89	90	91	92	Total
4	Power for SO_2 Control Equipment	Megawatts	Input																					
5	Power for By-Product Plant	Megawatts	Input																					
6	Total	Megawatts	(4) + (5)																					
7	Energy Required	Billion kwhr	$8.766 \times 10^{-5} \times (6) \times (2)$	(See Notes)																				

Transmission Energy Loss

Line No.	Item	Units	Entry Source*	1973	74	75	76	77	78	79	80	81	82	83	84	85	86	87	88	89	90	91	92	Total
8	Power Loss	Megawatts	Input																					
9	Energy Loss	Billion kwhr	$8.766 \times 10^{-5} \times (8) \times (2)$																					

Other (specify)

Line No.	Item	Units	Entry Source*	1973	74	75	76	77	78	79	80	81	82	83	84	85	86	87	88	89	90	91	92	Total
10		Megawatts	Input																					
11		Billion kwhr	$8.766 \times 10^{-5} \times (10) \times (2)$																					

Energy Available for Distribution

Line No.	Item	Units	Entry Source*	1973	74	75	76	77	78	79	80	81	82	83	84	85	86	87	88	89	90	91	92	Total
12	Energy Available	Billion kwhr	(3) - (7) - (9) - (11)	14.64		(Use average value of 10.98 for planning period)																	7.32	219.6

* Numbers in parentheses refer to line number on form.

Notes: Energy required for SO_2 control equipment and by-product plant not calculated - costed in analysis of SO_2 control costs.

Analysis Identification BCL-1A

Date Prepared 10/15/68

Analyst HEC/RES/AWL/BLF

FIGURE 41. FORM E - ENERGY GENERATED AND ENERGY AVAILABLE FOR DISTRIBUTION

			Year →	1973	74	75	76	77	78	79	80	81	82	83	84	85	86	87	88	89	90	91	92	
Line No.	Item	Units	Entry Source*											Coal Consumption										Total
1	Energy Generated	10^9 kwhr	Form E, Line (3)	14.64	(Use average value of 10.98 for planning period)																		7.32	219.6
2	Heat Rate	10^3 Btu/kwhr	Input	9.0	→																			☒
3	Total Btu Required	10^{12} Btu	(1) x (2)	132	(Use average value of 99 for planning period)																		66	1980
4	Btu/Lb of Coal	10^3 Btu/lb	Input	12.0	→																			☒
5	Btu/Ton of Coal	10^6 Btu/ton	2.0 x (4)	24.0	→																			☒
6	Coal Consumed	10^6 tons	(3) ÷ (5)	5.50	(Use average value of 4.125 for planning period)																		2.75	82.5
										Coal Cost														
					If cost in ¢ / million Btu																			
7	"As-Burned" Cost	¢ / million Btu	Input	24.0	→																			☒
8	Total Cost	Million $	(3) x (7) x 10^{-2}	31.68	(Use average value of 23.76 for planning period)																		15.84	475.2
					If cost in $/ton																			
9	"As-Burned" Cost	$/Ton	Input																					☒
10	Total Cost	Million $	(6) x (9)																					
										Sulfur Content														
11	Sulfur Content	Weight %	Input	3.0	→																			☒
12	Total Sulfur	10^3 long tons	(6) x (11) x 8.93	147.3	(Use average value of 110.5 for planning period)																		73.7	2210

* Numbers in parentheses refer to line number of form.

Notes: Totals based on 60 percent average capacity factor. The entries for 1973 show values corresponding to an 80 percent capacity factor; those for 1992, a 40 percent capacity factor.

Analysis Identification BCL-1A

Date Prepared 10/15/68

Analyst HEC/AWL/BLF

FIGURE 42. FORM FC – COAL CONSUMPTION AND COST AND SULFUR CONTENT SUMMARY

Line No.	Item	Entry Source*	Year → 1973	74	75	76	77	78	79	80	81	82	83	84	85	86	87	88	89	90	91	92	Total
			Annual Recurring Cost, millions of dollars																				
	Fuel																						
1	Fuel	Form FC, FO, or FG	31.68	(Use average value of 23.76 for planning period)																		15.84	475.2
	Power Plant																						
2	Operations**	Input	6.60	(Use average value of 4.95 for planning period)																		3.30	99.0
3	Maintenance**	Input																					
4	Annual Taxes (nonincome)	Input	4.86																			→	97.2
5	Annual Insurance	Input	0.38																			→	7.6
6	Subtotal	(2) + (3) + (4) + (5)	11.84	(Use average value of 10.19 for planning period)																		8.54	203.8
	Transmission Facilities																						
7	Operations**	Input																					
8	Maintenance**	Input																					
9	Annual Taxes (nonincome)	Input																					
10	Annual Insurance	Input																					
11	Subtotal	(7) + (8) + (9) + (10)																					
	Net – SO_2-Control-Process Equipment, By-Product Plant and Income																						
12	Net – SO_2 Control, etc.	(27) – from p. 2, Form R	1.30	(Use average value of 1.485 for planning period)																		1.67	29.7
	Net – Annual Recurring Costs																						
13	Net	(1) + (6) + (11) + (12)	44.82	(Use average value of 35.40 for planning period)																		26.05	708.0

*Numbers in parentheses refer to line number of form.
**If operations and maintenance not costed separately, enter on "Operations", Lines (2) and (7).

Notes: Line (4) value based on 1.8 percent of nonrecurring cost. Line (5) value based on 0.14 percent of nonrecurring cost.

Analysis Identification BCL-1A
Date Prepared 10/16/68
Analyst HEC/AWL/BLF

FIGURE 43. FORM R (p. 1 of 2) – RECURRING COST SUMMARY

Year → 1973–92

Annual Recurring Cost, millions of dollars

SO$_2$-Control-Process Equipment***

Line No.	Item	Entry Source*	1973	74	75	76	77	78	79	80	81	82	83	84	85	86	87	88	89	90	91	92	
14	Operations**	Input	5.15	(Use average value of 4.275 for planning period)																		3.4	85.5
15	Maintenance**	Input																					
16	Annual Taxes (nonincome)	Input	0.36	→																			7.2
17	Annual Insurance	Input	0.03	→																			0.6
18	Subtotal	(14) + (15) + (16) + (17)	5.54	(Use average value of 4.665 for planning period)																		3.79	93.3

By-Product Plant

Line No.	Item	Entry Source*	1973	74	75	76	77	78	79	80	81	82	83	84	85	86	87	88	89	90	91	92	
19	Operations**	Input																					
20	Maintenance**	Input																					
21	Annual Taxes (nonincome)	Input																					
22	Annual Insurance	Input																					
23	Subtotal	(19) + (20) + (21) + (22)																					

Income From By-Product Sales

Line No.	Item	Entry Source*	1973	74	75	76	77	78	79	80	81	82	83	84	85	86	87	88	89	90	91	92	
24	Production, 1000 long tons	Input	132.6	(Use average value of 99.45 for planning period)																		66.3	1989
25	Sales Price $/long ton	Input	32.0	→																			☒
26	Income, million $	(24) x (25) x 10^{-3}	4.24	(Use average value of 3.18 for planning period)																		2.12	63.6

Net

Line No.	Item	Entry Source*	1973	74	75	76	77	78	79	80	81	82	83	84	85	86	87	88	89	90	91	92	
27	Net - SO$_2$ Control, etc.	(18) + (23) - (26)	1.30	(Use average value of 1.485 for planning period)																		1.67	29.7

* Numbers in parentheses refer to line number of form.
** If operations and maintenance not costed separately, enter on "Operations", Lines (2) and (7).
*** If SO$_2$-control-process equipment and by-product plant not costed separately, enter on Lines (14) through (18).

Notes: ______

Analysis Identification BCL-1A
Date Prepared 10/16/68
Analyst HEC/AWL/BLF

FIGURE 43 (CONTINUED). FORM R (p. 2 of 2) - RECURRING COST SUMMARY elements. Details of the computations are not included here since they correspond to those of the previous complete examples. Results are shown in a format similar to Form S (Figure 11) but into which additional information on the elements of cost, both nonrecurring and recurring, have been inserted.

Examples have been included both for actual planned facilities and for hypothetical installations. Some of the examples correspond to facilities under construction or being planned by utilities visited during the course of this program. Thus, a qualitative comparison can be made between the results obtained by the utilities in their planning studies and those presented here. For simplicity in developing these examples, the analysis has been performed for a period of only 1 year rather than the normal period of 20 or 30 years. In other words, it has been assumed that the operations do not vary over the period of interest.

Annualized nonrecurring costs have been computed on the basis of a 20-year period using a 7 percent interest rate for money. Thus, the multiplying factor would be 13.99 percent, including income taxes, etc.

New York City Service Area

For the New York City service area, an analysis has been performed on the basis of a hypothetical new installation having a generating capacity of 800 megawatts. The practice in this area is to locate the generation station within the service area primarily because rights-of-way for overhead transmission lines to lead from remote generation facilities are not available.

Three cost examples have been computed. These are shown in Table 29. Column 1 shows a conventional oil-fired installation, while Column 2 indicates the effect of adding an alkalized-alumina control device to remove 90 percent of the SO_2 being emitted. A remote-location alternative is shown in Column 3. The transmission-line costs have been computed for a total length of 340 miles, with the last 40 miles being underground as would be required because rights-of-way for overhead lines are not available.

Comparison of the costs for energy delivered to the local distribution network of New York City indicates that the penalty for SO_2 control by the alkalized-alumina process is about 0.40 mill. In other words, the value of the sulfur recovered is not sufficient to compensate for the cost incurred in recovery. This is further illustrated by the value of $51/long ton shown in Table 29 as the cost for removing a long ton of sulfur. This is after credit for the predicted net sales value of $29.60/long ton which might be realized in the 1970 to 1975 time period in the New York area has been taken.

As indicated by Column 3 of Table 29, the cost of electrical power remotely generated and transmitted to the New York service area would not be competitive with locally generated power. The primary reason for this is the excessive cost for the underground transmission needed over the last 40 miles of the 340 miles total distance. The underground portion of this transmission line has been estimated to cost $61 million, representing 30 percent of the estimated total investment for the project. Without this requirement for underground transmission, however, a competitive cost might be achieved for remote generation.

TABLE 29. COSTS FOR POWER GENERATION AT A HYPOTHETICAL 800-Mw GENERATION PLANT SERVING THE NEW YORK CITY AREA

Number of Generating Units: 1

Plant Factor: 70 percent

New York Location
Fuel: Coal (3 percent sulfur, 12,000 Btu/lb)

Fuel Cost: 31¢/million Btu

Remote Pennsylvania Location
Fuel: Coal (2 percent sulfur, 12,800 Btu/lb)

Fuel Cost: 19¢/million Btu

Line No.	Item	Units	Conventional Coal	Coal With Alkalized-Alumina Control	Remote Pennsylvania Location With Coal
	Electric Plant	Million $	127	127	93
	Transmission Line	Million $	--	--	109
	SO_2-Control Device	Million $	--	8.5	--
1	Total Nonrecurring Cost	Million $	127	135.5	200
2	Nameplate Generating Capacity	Mw	800	800	800
3	Dollars/Kilowatt	$/kw	159	169	250
	Electric Plant O&M	Million $	2.75	2.75	1.96
	Transmission Plant Maintenance	Million $	--	--	1.09
	SO_2-Control Plant O&M	Million $	--	1.90	--
	Real Estate Taxes & Insurance	Million $	2.90	3.10	3.00
	Fuel Cost	Million $	13.70	13.70	8.40
	Sulfur (or H_2SO_4) Credit	Million $	--	1.23	--
4	Total Recurring Costs	Million $	19.35	20.22	14.45
5	Total Annualized Nonrecurring Costs	Million $	17.80	18.90	28.00
6	Total Cost	Million $	37.15	39.12	42.45
7	Total Energy for Distribution	10^9 kwhr	4.91	4.91	4.71
8	Cost/Energy	Mills/kwhr	7.57	7.97	9.01
9	Incremental Cost for SO_2 Control	Mills/kwhr	--	0.40	--
10	Total Sulfur Content of Fuel	10^3 long tons	43.0	43.0	30.0
11	Total Sulfur Removed	10^3 long tons	--	38.7	--
12	Net Cost/Long Ton of Sulfur Removed	$/ton	--	51	--

Another alternative would be nuclear generation, and this has been indicated as the way future needs in the New York service area will be met. Although such a case has not been computed, the cost for electricity would probably be only slightly more than the 5.88 mills/kwhr (say 6.5 mills/kwhr) estimated for nuclear generation in the Baltimore area (see Table 30). Thus, nuclear generation seems to be already more than competitive with other postulated alternatives, including local generation without low-sulfur fuels or without SO_2-control processes.

Baltimore Service Area

A fairly complete set of alternatives has been computed for the Baltimore service area. These are shown in Table 30. Generation using coal as the fuel is shown in the first seven columns, while that using oil is shown in the next three. The last column shows the predicted costs for nuclear generation.

Included in this set of examples is a computation of expected costs for the two SO_2-control processes for which data have been assembled: alkalized alumina and catalytic oxidation. Alternative costs for the catalytic-oxidation control process as shown by a recent Monsanto brochure(39) have also been estimated (see Column 5).

Application of the various control processes to coal- and oil-fired operation resulted in estimated incremental costs of from 0.39 to 0.57 mill/kwhr. The use of low-sulfur oil as a fuel is predicted to increase costs by 0.66 mill/kwhr over that for oil of normal sulfur (3 percent) content.

Remote generation at a mine-mouth station near Conemaugh with two 200-mile transmission lines being used to transport power to the Baltimore transmission system does not appear to be competitive either with or without SO_2 control. Nuclear generation (shown in Column 11), however, does appear to be competitive, as does the low-sulfur-oil alternative, with the alternatives employing any one of the several control alternatives. Broadly speaking, the use of oil as a fuel appears to be slightly less costly than the use of coal at this particular location.

Central Kentucky Service Area

Table 31 shows cost estimates for a mine-mouth generation facility in the west-central Kentucky region. This represents the situation for a new unit which might be postulated for the mine-mouth Paradise Station on the Green River near Drakesboro. Burning coal containing 3 percent sulfur and costing 13¢/million Btu, the base cost of electrical power is predicted as 4.47 mills/kwhr. The incremental cost for SO_2 control using the alkalized-alumina process would be 0.31 mill/kwhr.

Southeastern Ohio Service Area

Two examples are shown in Table 32 for electric power generation in the southeastern Ohio coal fields. For a 600-Mw generating station having two 300-Mw units and operating at an 80 percent load factor, the base cost would be 5.10 mills/kwhr. Sulfur control through the use of the alkalized-alumina process has been estimated to add 0.44 mill/kwhr to the generation cost.

TABLE 30. COSTS FOR POWER GENERATION AT A HYPOTHETICAL 840-Mw GENERATION PLANT SERVING THE BALTIMORE AREA

Number of Generating Units: 2 (except 1 for nuclear)

Plant Factor: 80 percent

Baltimore Location
Fuel: Coal (3 percent sulfur, 12,500 Btu/lb)
Oil (3 percent sulfur, 18,700 Btu/lb)
Low-sulfur oil (1 percent sulfur, 18,700 Btu/lb)

Fuel Cost: Coal, 29¢/million Btu
Oil, 31¢/million Btu
Low-sulfur oil, 38¢/million Btu

Remote Pennsylvania Location
Fuel: Coal (3 percent sulfur, 13,500 Btu/lb)

Fuel Cost: 19¢/million Btu

Line No.	Item	Units	Conventional Coal	Coal With Alkalized-Alumina Control	Coal With Catalytic-Oxidation Control (Katell Costs)	Coal With Catalytic-Oxidation Control (Monsanto Costs)	Remote Pennsylvania Location With Coal	Remote Pennsylvania Location With Coal, Alkalized-Alumina Control	Conventional Oil	Oil With Alkalized-Alumina Control	Low-Sulfur Oil	Nuclear
	Electric Plant	Million $	92	92	92	92	110	110	74	74	74	147
	Transmission Line	Million $	--	--	--	--	52.4	52.4	--	--	--	--
	SO_2-Control Device	Million $	--	11.2	23	21.0	--	11.2	--	11.2	--	--
1	Total Nonrecurring Cost	Million $	92	103.2	115	113.0	162.4	173.6	74	85.2	74	147
2	Nameplate Generating Capacity	Mw	840	840	840	840	840	840	840	840	840	840
3	Dollars/Kilowatt	$/kw	110	123	137	135	192	206	88	102	88	175
	Electric Plant O&M	Million $	2.30	2.30	2.30	2.30	2.42	2.42	1.77	1.77	1.77	1.60
	Transmission Plant Maintenance	Million $	--	--	--	--	0.52	0.52	--	--	--	--
	SO_2 Control Plant O&M	Million $	--	2.40	2.00	2.50	--	2.40	--	2.40	--	--
	Real Estate Taxes and Insurance	Million $	1.56	1.76	1.95	1.93	2.44	2.60	1.26	1.45	1.26	3.09
	Fuel Cost	Million $	15.45	15.45	15.45	15.45	10.10	10.10	17.10	17.10	21.00	9.40
	Sulfur (or H_2SO_4) Credit	Million $	--	1.41	3.26	3.26	--	1.41	--	1.05	--	--
4	Total Recurring Costs	Million $	19.31	20.50	18.44	18.92	15.48	16.63	20.13	21.67	24.03	14.09
5	Total Annualized Nonrecurring Costs	Million $	12.90	14.50	16.10	15.85	22.40	24.00	10.35	11.95	10.35	20.55
6	Total Cost	Million $	32.21	35.00	34.54	34.77	37.88	40.63	30.48	33.62	34.38	34.64
7	Total Energy for Distribution	10^9 kwhr	5.91	5.91	5.91	5.91	5.65	5.65	5.91	5.91	5.91	5.91
8	Cost/Energy	Mills/kwhr	5.45	5.92	5.84	5.88	6.70	7.19	5.16	5.69	5.82	5.86
9	Incremental Cost for SO_2 Control	Mills/kwhr		0.47	0.39	0.43	--	0.49	--	0.53	0.66	--
10	Total Sulfur Content of Fuel	10^3 long tons	52.8	52.8	52.8	52.8	52.8	52.8	39.4	39.4	13.1	--
11	Total Sulfur Removed	10^3 long tons		47.5	47.5	47.5	--	47.5	--	35.5	--	--
12	Cost/Ton of Sulfur Removed	$/long ton		59	49	54	--	58	--	88	--	--

TABLE 31. COSTS FOR POWER GENERATION AT A HYPOTHETICAL 800-Mw GENERATION PLANT SERVING THE KENTUCKY AREA

Number of Generating Units: 1

Plant Factor: 70 percent

Fuel: Coal (3 percent sulfur, 11,100 Btu/lb)

Fuel Cost: 13¢/million Btu

Line No.	Item	Units	Conventional Coal	Coal With Alkalized-Alumina Control
	Electric Plant	Million $	100	100
	Transmission Line	Million $	--	--
	SO_2-Control Device	Million $	--	8.5
1	Total Nonrecurring Cost	Million $	100	108.5
2	Nameplate Generating Capacity	Mw	800	800
3	Dollars/Kilowatt	$/kw	125	136
	Electric Plant O&M	Million $	2.16	2.16
	Transmission Plant Maintenance	Million $	--	--
	SO_2 Control Plant O&M	Million $	--	1.90
	Real Estate Taxes and Insurance	Million $	1.00	1.08
	Fuel Cost	Million $	5.74	5.74
	Sulfur (or H_2SO_4) Credit	Million $	--	1.54
4	Total Recurring Costs	Million $	8.90	9.34
5	Total Annualized Nonrecurring Costs	Million $	13.04	14.15
6	Total Cost	Million $	21.94	23.49
7	Total Energy for Distribution	10^9 kwhr	4.91	4.91
8	Cost/Energy	Mills/kwhr	4.47	4.78
9	Incremental Cost for SO_2 Control	Mills/kwhr	--	0.31
10	Total Sulfur Content of Fuel	10^3 long tons	53.7	53.7
11	Total Sulfur Removed	10^3 long tons	--	48.3
12	Cost/Ton of Sulfur Removed	$/long ton	--	32

TABLE 32. COSTS FOR POWER GENERATION AT A HYPOTHETICAL 600-Mw GENERATION PLANT SERVING THE OHIO AREA

Number of Generating Units: 2

Plant Factor: 80 percent

Fuel: Coal (3 percent sulfur, 10,400 Btu/lb)

Fuel Cost: 16¢/million Btu

Line No.	Item	Units	Conventional Coal	Coal With Alkalized-Alumina Control
	Electric Plant	Million $	90	90
	Transmission Line	Million $	--	--
	SO_2-Control Device	Million $	--	9.2
1	Total Nonrecurring Cost	Million $	90	99
2	Nameplate Generating Capacity	Mw	600	600
3	Dollars/Kilowatt	$/kw	150	165
	Electric Plant O&M	Million $	2.23	2.23
	Transmission Plant Maintenance	Million $	--	--
	SO_2 Control Plant O&M	Million $	--	1.90
	Real Estate Taxes and Insurance	Million $	1.43	1.58
	Fuel Cost	Million $	6.05	6.05
	Sulfur (or H_2SO_4) Credit	Million $	--	1.37
4	Total Recurring Costs	Million $	9.71	10.39
5	Total Annualized Nonrecurring Costs	Million $	11.75	12.92
6	Total Cost	Million $	21.46	23.31
7	Total Energy for Distribution	10^9 kwhr	4.21	4.21
8	Cost/Energy	Mills/kwhr	5.10	5.54
9	Incremental Cost for SO_2 Control	Mills/kwhr	--	0.44
10	Total Sulfur Content of Fuel	10^3 long tons	48.7	48.7
11	Total Sulfur Removed	10^3 long tons	--	43.8
12	Cost/Ton of Sulfur Removed	$/long ton	--	42

Northern Indiana Service Area

Northern Indiana was selected as an example because this represents an area where future service will be provided by a nuclear facility currently under construction, i.e., at St. Joseph, Michigan. Table 33 summarizes the results of the cases considered.

As will be observed, nuclear generation is competitive with power generated locally burning a 3 percent sulfur coal without a sulfur control device. Estimated costs are 5.28 and 5.29 mills/kwhr, respectively. There is no significance to the variation in the third significant figure shown; it is carried only for convenience.

Generation at a remote location (central Indiana at mine mouth) with transmission by twin lines, each 180 miles in length, to the service area would result in a power cost of 5.81 mills/kwhr. Obviously, this alternative is not competitive even though this is the one currently in use, with power being transmitted into this service area from both central Indiana and southeastern Ohio.

An interesting result of these alternatives that have been evaluated is that the net incremental cost for control using the alkalized-alumina process is less for a 5 percent sulfur coal than for a 3 percent sulfur coal. Thus, there appears to be merit for attempting to produce as much sulfur as possible once the facility is available. The comparison was made using an assumed constant value for sulfur and on the basis that the stack-effluent concentration of SO_2 was the same in both cases.

Salt Lake City Service Area

Table 34 shows an example of the estimated cost for a mine-mouth plant serving the Salt Lake City area. The example is for a 40-mile transmission distance using a single circuit line, from the Castle Gate location east and north of Salt Lake City where coal deposits are known to be. The estimated cost of power, 4.89 mills/kwhr, is one of the lower values found even though fuel cost is not particularly low and transmission over a 40-mile distance is required.

Dallas Service Area

The example shown in Table 35 for the Dallas service area indicates the low generated cost, 3.67 mills/kwhr, that can be achieved through the use of natural gas as a fuel. In this area close to natural gas supplies, the fuel cost is low. Also, a generating station using natural gas as a fuel has the lowest initial as well as maintenance and other costs. Thus, this example probably represents near to the lowest power cost achievable in the United States for a fossil fuel plant.

Los Angeles Service Area

Shown in Table 36 are cost-computation examples for four alternatives for serving the Los Angeles service area. An oil-fired facility using oil with 3 percent sulfur content is estimated to result in the lowest cost for generated power. Somewhat higher in cost (by 0.41 mill/kwhr) is a facility using alkalized-alumina control. Use of low-sulfur oil as a fuel would result in an incremental increase almost double (0.74 vs 0.41 mill/kwhr) that for alkalized-alumina control.

TABLE 33. COSTS FOR POWER GENERATION AT A HYPOTHETICAL 2082-Mw GENERATION PLANT SERVING THE NORTHERN INDIANA AREA

Number of Generating Units: 2

Plant Factor: 80 percent

Northern Indiana Location
Fuel: Coal (3 percent sulfur, 11,000 Btu/lb)
Low-sulfur coal (1 percent sulfur, 11,000 Btu/lb)
High-sulfur coal (5 percent sulfur, 11,000 Btu/lb)

Fuel Cost: Coal, 24¢/million Btu
Low-sulfur coal, 28¢/million Btu
High-sulfur coal, 24¢/million Btu

Remote Central Indiana Location
Fuel: Coal (3 percent sulfur, 11,000 Btu/lb)
Fuel Cost: 20¢/million Btu

Line No.	Item	Units	Conven-tional Coal	Low-Sulfur Coal	Coal With Alkalized-Alumina Control	High-Sulfur Coal With Alkalized-Alumina Control	Remote Central Indiana Location With Coal	Remote Central Indiana Location With Coal, Alkalized-Alumina Control	Nuclear
	Electric Plant	Million $	271	271	271	271	271	271	340
	Transmission Line	Million $	--	--	--	--	73	73	--
	SO_2-Control Device	Million $	--	--	20	24	--	20	--
1	Total Nonrecurring Cost	Million $	271	271	291	295	344	364	340
2	Nameplate Generating Capacity	Mw	2082	2082	2082	2082	2082	2082	2082
3	Dollars/Kilowatt	$/kw	130	130	140	141	165	174	163
	Electric Plant O&M	Million $	6.61	6.61	6.61	6.61	6.61	6.61	3.66
	Transmission Plant Maintenance	Million $	--	--	--	--	0.67	0.67	--
	SO_2 Control Plant O&M	Million $	--	--	5.40	6.90	--	5.40	--
	Real Estate Taxes and Insurance	Million $	3.79	3.79	4.06	4.13	4.81	5.09	5.77
	Fuel Cost	Million $	31.60	36.80	31.60	31.60	26.30	26.30	23.40
	Sulfur (or H_2SO_4) Credit	Million $	--	--	4.61	7.68	--	4.61	--
4	Total Recurring Costs	Million $	42.00	47.20	43.06	41.56	38.39	39.46	32.83
5	Total Annualized Nonrecurring Costs	Million $	35.30	35.30	38.00	38.40	44.80	47.50	44.30
6	Total Cost	Million $	77.30	82.50	81.06	79.96	83.19	86.96	77.13
7	Total Energy for Distribution	10^9 kwhr	14.61	14.61	14.61	14.61	14.32	14.32	14.61
8	Cost/Energy	Mills/kwhr	5.29	5.65	5.55	5.47	5.81	6.07	5.28
9	Incremental Cost for SO_2 Control	Mills/kwhr	--	0.36	0.26	0.16	--	0.26	--
10	Total Sulfur Content of Fuel	10^3 long tons	160	53	160	266	160	160	--
11	Total Sulfur Removed	10^3 long tons	--	--	144	240	--	144	--
12	Cost/Ton of Sulfur Removed	$/long ton	--	--	26	11	--	19	--

TABLE 34. COSTS FOR POWER GENERATION AT A HYPOTHETICAL 800-Mw GENERATION PLANT SERVING THE SALT LAKE CITY AREA

Number of Generating Units: 1

Plant Factor: 80 percent

Remote Castle Gate Location
Fuel: Coal (1 percent sulfur, 12,700 Btu/lb)

Fuel Cost: 23¢/million Btu

Line No.	Item	Units	Coal
	Electric Plant	Million $	84.0
	Transmission Line	Million $	8.9
	SO_2-Control Device	Million $	--
1	Total Nonrecurring Cost	Million $	92.9
2	Nameplate Generating Capacity	Mw	800
3	Dollars/Kilowatt	$/kw	116
	Electric Plant O&M	Million $	2.07
	Transmission Plant Maintenance	Million $	0.09
	SO_2 Control Plant O&M	Million $	--
	Real Estate Taxes and Insurance	Million $	1.21
	Fuel Cost	Million $	11.60
	Sulfur (or H_2SO_4) Credit	Million $	--
4	Total Recurring Costs	Million $	14.97
5	Total Annualized Nonrecurring Costs	Million $	12.30
6	Total Cost	Million $	27.27
7	Total Energy for Distribution	10^9 kwhr	5.58
8	Cost/Energy	Mills/kwhr	4.89
9	Incremental Cost for SO_2 Control	Mills/kwhr	--
10	Total Sulfur Content of Fuel	10^3 long tons	17.8
11	Total Sulfur Removed	10^3 long tons	--
12	Cost/Ton of Sulfur Removed	$/long ton	--

TABLE 35. COSTS FOR POWER GENERATION AT A HYPOTHETICAL 800-Mw GENERATION PLANT SERVING THE DALLAS AREA

Number of Generating Units: 1

Plant Factor: 80 percent

Dallas Location
Fuel: Gas (1000 Btu/cu ft, no sulfur)

Fuel Cost: 20¢/million Btu

Line No.	Item	Units	Gas
	Electric Plant	Million $	56.0
	Transmission Line	Million $	--
	SO_2-Control Device	Million $	--
1	Total Nonrecurring Cost	Million $	57.6
2	Nameplate Generating Capacity	Mw	800
3	Dollars/Kilowatt	$/kw	72
	Electric Plant O&M	Million $	1.40
	Transmission Plant Maintenance	Million $	--
	SO_2 Control Plant O&M	Million $	--
	Real Estate Taxes and Insurance	Million $	0.69
	Fuel Cost	Million $	10.90
	Sulfur (or H_2SO_4) Credit	Million $	--
4	Total Recurring Costs	Million $	12.99
5	Total Annualized Nonrecurring Costs	Million $	7.59
6	Total Cost	Million $	20.58
7	Total Energy for Distribution	10^9 kwhr	5.61
8	Cost/Energy	Mills/kwhr	3.67
9	Incremental Cost for SO_2 Control	Mills/kwhr	--
10	Total Sulfur Content of Fuel	10^3 long tons	0
11	Total Sulfur Removed	10^3 long tons	--
12	Cost/Ton of Sulfur Removed	$/long ton	--

TABLE 36. COSTS FOR POWER GENERATION AT A HYPOTHETICAL 800-Mw GENERATION PLANT SERVING THE LOS ANGELES AREA

Number of Generating Units: 1

Plant Factor: 80 percent

Los Angeles Location
Fuel: Oil (3 percent sulfur, 18,700 Btu/lb)
Low-sulfur oil (1 percent sulfur, 18,700 Btu/lb)

Fuel Cost: Oil, 30¢/million Btu
Low-sulfur oil, 38¢/million Btu

Remote New Mexico Location
Fuel: Coal (1 percent sulfur, 9,000 Btu/lb)

Fuel Cost: 14¢/million Btu

Line No.	Item	Units	Conventional Oil	Low-Sulfur Oil	Oil With Alkalized-Alumina Control	Remote New Mexico Generation With Coal
	Electric Plant	Million $	82	82	82	84
	Transmission Line	Million $	--	--	--	109
	SO_2-Control Device	Million $	--	--	8.5	--
1	Total Nonrecurring Cost	Million $	82	82	90.5	193
2	Nameplate Generating Capacity	Mw	800	800	800	800
3	Dollars/Kilowatt	$/kw	102	102	113	238
	Electric Plant O&M	Million $	2.02	2.02	2.02	2.07
	Transmission Plant Maintenance	Million $	--	--	--	1.09
	SO_2 Control Plant O&M	Million $	--	--	2.10	--
	Real Estate Taxes and Insurance	Million $	1.28	1.28	1.44	2.32
	Fuel Cost	Million $	15.74	19.92	15.74	7.08
	Sulfur (or H_2SO_4) Credit	Million $	--	--	1.08	--
4	Total Recurring Costs	Million $	19.04	23.22	20.22	12.56
5	Total Annualized Nonrecurring Costs	Million $	10.68	10.68	11.79	24.70
6	Total Cost	Million $	29.72	33.90	32.01	37.26
7	Total Energy for Distribution	10^9 kwhr	5.61	5.61	5.61	5.14
8	Cost/Energy	Mills/kwhr	5.30	6.04	5.71	7.25
9	Incremental Cost for SO_2 Control	Mills/kwhr	--	0.74	0.41	--
10	Total Sulfur Content of Fuel	10^3 long tons	37.4	12.5	37.4	25.1
11	Total Sulfur Removed	10^3 long tons	--	--	33.7	--
12	Cost/Ton of Sulfur Removed	$/long ton	--	--	67	--

The other alternative explored was remote generation at mine mouth in the Four Corners area plus transmission over a distance of 700 miles to the service area. This alternative is not competitive, costing almost 2 mills/kwhr more than the base case using high-sulfur oil without control. However, enlargement of this power-generation station is under way in this location with the fourth unit, having a 755-Mw capacity, scheduled for completion in 1969 and the fifth in 1970. The only obvious factor that cannot be evaluated for this alternative is the interaction which undoubtedly exists between the transmission facilities for power from this location and those serving Glen Canyon and Hoover Dams.

Tampa Service Area

The Tampa area, examples for which are shown in Table 37, would normally generate power using oil containing about 3 percent sulfur as a fuel. This base case is shown in Column 1. Columns 2 and 3 indicate that low-sulfur oil and alkalized-alumina-control alternatives would be more costly by about the same increment, 0.47 and 0.43 mill/kwhr, respectively, than the base case. Generation using coal as a fuel appears to be cheaper than that using oil. An interesting alternative, apparently worth considering for this area, would be the use of coal as a fuel with the alkalized-alumina process being used for control. This alternative would have an incremental cost only 0.15 mill/kwhr higher than that of generation using 3 percent sulfur oil as a fuel.

Summary of Estimated Costs

Table 38 is a summary of the estimated costs of power delivered to the distribution network. Although not comparable in an absolute sense because of differences in generating-unit sizes, load factors, etc., some interesting observations are possible.

Costs for power delivered to the distribution network are about 5 mills/kwhr in most parts of the United States. However, there are some significant deviations. For example, for locations in and near the natural-gas fields where natural gas is used as the fuel, estimated costs are somewhat lower. The cost in Dallas, which was one of the examples computed, was estimated to be 3.67 mills/kwhr. There appear to be two reasons for this. First, the fuel cost (at 20¢/million Btu), although not the lowest, is in the lower part of the range. Second, the capital cost of the generating plant is low, both because a boiler using natural gas as a fuel has a lower cost and because Dallas is in a low-construction-cost region.

The cost of power delivered to the generation network in New York City can be contrasted with this; here the cost is the highest of those estimated. Obvious reasons are the high cost of fuel and the high cost of construction.

Several interesting general trends can be observed by study of this summary table. Nuclear generation appears to be competitive in all areas except possibly in those regions where fossil fuel is available locally and can be obtained without incurring high labor and transportation costs. Dallas and Kentucky are prime examples here.

Remote generation does not appear to be a viable alternative. The transmission costs for any significant distance are so large that other alternatives appear to have lesser cost. For example, rail hauling of coal, particularly in unit trains, over distances

TABLE 37. COSTS FOR POWER GENERATION AT A HYPOTHETICAL 800-Mw GENERATION PLANT SERVING THE TAMPA AREA

Number of Generating Units: 1

Plant Factor: 80 percent

Tampa Location
Fuel: Oil (3 percent sulfur, 18,700 Btu/lb)
Low-sulfur oil (1 percent sulfur, 18,700 Btu/lb)
Coal (3 percent sulfur, 11,400 Btu/lb)

Fuel Cost: Oil, 33¢/million Btu
Low-sulfur oil, 38¢/million Btu
Coal, 27¢/million Btu

Line No.	Item	Units	Conventional Oil	Low-Sulfur Oil	Oil With Alkalized-Alumina Control	Conventional Coal	Coal With Alkalized-Alumina Control
	Electric Plant	Million $	59	59	59	74	74
	Transmission Line	Million $	--	--	--	--	--
	SO_2-Control Device	Million $	--	--	8.5	--	8.5
1	Total Nonrecurring Cost	Million $	59	59	67.5	74	82.5
2	Nameplate Generating Capacity	Mw	800	800	800	800	800
3	Dollars/Kilowatt	$/kw	74	74	84	92	103
	Electric Plant O&M	Million $	1.40	1.40	1.40	1.74	1.74
	Transmission Plant Maintenance	Million $	--	--	--	--	--
	SO_2 Control Plant O&M	Million $	--	--	2.10	--	2.10
	Real Estate Taxes and Insurance	Million $	0.77	0.77	0.88	0.96	1.07
	Fuel Cost	Million $	17.30	19.92	17.30	13.62	13.62
	Sulfur (or H_2SO_4) Credit	Million $	--	--	1.00	--	1.57
4	Total Recurring Costs	Million $	19.47	22.09	20.68	16.32	16.96
5	Total Annualized Nonrecurring Costs	Million $	8.23	8.23	9.40	10.32	11.50
6	Total Cost	Million $	27.70	30.32	30.08	26.64	28.46
7	Total Energy for Distribution	10^9 kwhr	5.61	5.61	5.61	5.61	5.61
8	Cost/Energy	Mills/kwhr	4.93	5.40	5.36	4.75	5.08
9	Incremental Cost for SO_2 Control	Mills/kwhr	--	0.47	0.43	--	0.33
10	Total Sulfur Content of Fuel	10^3 long tons	37.4	12.5	37.4	59.3	59.3
11	Total Sulfur Removed	10^3 long tons	--	--	33.7	--	53.2
12	Cost/Ton of Sulfur Removed	$/long ton	--	--	71	--	34

TABLE 38. SUMMARY OF ESTIMATED COSTS OF POWER DELIVERED TO DISTRIBUTION NETWORK

		Estimated Costs, mills/kwhr				
Service Area	Fuel	Conventional	Remote Location	Alkalized-Alumina Control	Catalytic-Oxidation Control	Nuclear
New York City	Coal (3% S)	7.57		7.97		(5.86)(c)
	Coal (2% S)		9.01			
Baltimore	Coal (3% S)	5.45	6.70 (7.19)(a)	5.92	5.84 (5.88)(b)	5.86
	Oil (3% S)	5.16		5.69		
	Oil (1% S)	5.82				
Kentucky	Coal (3% S)	4.47		4.78		
Ohio	Coal (3% S)	5.10		5.54		
Northern Indiana	Coal (5% S)			5.47		
	Coal (3% S)	5.29	5.81 (6.07)(a)	5.55		5.28
	Coal (1% S)	5.65				
Salt Lake City	Coal (1% S)		4.89			
Dallas	Natural gas	3.67				
Los Angeles	Oil (3% S)	5.30		5.71		
	Oil (1% S)	6.04				
	Coal (1% S)		7.25			
Tampa	Oil (3% S)	4.93		5.36		
	Oil (1% S)	5.40				
	Coal (3% S)	4.75		5.08		

(a) Alkalized-alumina control.

(b) Monsanto costs.

(c) Obtained from Baltimore example.

of 200 miles or more (if there is already a rail line in existence) appears to be cheaper. The estimates for Baltimore and Northern Indiana show this. The New York City estimates for remote generation are more costly yet because of the necessity for underground transmission lines for part of the distance from any remote generation station.

Using currently available estimates of SO_2-control-process costs as previously discussed, Table 38 indicates that incremental costs for control approximate 0.5 mill/kwhr, essentially independent of the two processes costed. There are variations in this value, of course, which depend on the size of the installation, degree of removal, sulfur market values, etc., but the 0.5 mill/kwhr value might serve as a convenient rule of thumb.

One other feature of interest is the result, previously mentioned, that use of a higher sulfur fuel in conjunction with a control process would result in a slightly lower net cost for power. (See the values tabulated for the Northern Indiana service area, Table 33.) This suggests that if a SO_2-control process with recovery of a by-product is to be applied, use of a fuel with the largest content of sulfur available should be explored. Modification of this viewpoint, of course, would probably be necessary if the monetary value of sulfur or sulfuric acid becomes less.

Sensitivity of Results

Another reason for performing the computations summarized in Table 38 was to explore the sensitivity of power costs to a variation in each of the several cost components when combined according to the cost-model structure. A surprising result was the large influence of transmission distance in increasing the cost of power delivered to the distribution network. The results indicate that rail and/or barge hauling of coal and ocean and/or barge shipment of oil is much more advantageous even for distances as short as 180 miles. This conclusion is somewhat in opposition to current practices as exemplified by the Northern Indiana and Los Angeles service-area examples. Further exploration of transmission costs as contrasted to fuel transportation costs thus appears to be warranted.

Although better, more refined data would be desirable on the control-process costs, this cost component does not appear to be a large factor in the overall power cost. However, the value assigned to the sulfur or sulfuric acid does have a large percentage effect on the control cost and, thus, emphasis in future efforts should be placed here. The time variation of these values may also prove to have importance.

The variation of fuel, as burned, costs with time may also prove to be a significant factor. Since fuel cost represents 25 to 50 percent of the total cost per unit of power, the variation of the fuel cost as a function of time may have a strong influence. A situation where this might be expected is the example for the Dallas service area, where the fuel is natural gas. Here, a doubling of the price of natural gas, not inconceivable over a 20-year period, would increase the cost of power by 50 percent, from 3.67 to 5.51 mills/kwhr.

Finally, the results obtained are believed sensitive to plant factor although no exploration of the significance of this has been performed. This was primarily because no logic in the manner in which electric utilities perform their planning to account for this factor could be detected. For the most part, the utilities make comparisons of interesting alternatives at constant high plant factors of 80 to 90 percent, even though their system load factor may approximate 50 to 60 percent. The influence of such tactics on decisions reached needs to be explored, particularly when control-process needs begin to influence system operation.

CONCLUSIONS AND RECOMMENDATIONS

Development of a cost model to be used in evaluating the promise of SO_2-control processes has been achieved. Although the model is not as sophisticated as others developed in the past for other areas, such as aerospace, a planned balance between sophistication and utility was desired. Thus, ease of application and a fair degree of simplicity leading to short times for computation also exist.

The cost model which has been described in this report is applicable during each solution to only one of almost an infinite number of real or assumed situations. Thus, in its present form, costs for various locations, sizes, alternatives, etc., must be computed individually and compared before any conclusions can be reached. In other words, optimization techniques have not been built into the model.

In using the model, a few limitations should be recognized. The model will be valid only to the degree that the input data are accurate. Although a sensitivity analysis was performed in terms of the computation of numerous examples and alternatives, further effort is undoubtedly needed to permit discerning the areas where more accurate representations of cost are desirable because of the high sensitivity of results to certain cost representations. As with all cost-model studies, the cost data for utilizing the developed methodology are historically based. Therefore, periodic refinement and updating need to be performed. Finally, time and effort limitations will be recognized. Analysis for several alternatives for a given service area will take a significant time period, perhaps several days. Thus, in the present stage of development of the model, judicious selection of the locations and alternatives needs to be made.

To be used for planning purposes for SO_2-control-process development, solutions for a large number of planned facilities will undoubtedly be needed before a reasonable assurance as to the "best" programs can be discerned. The following activities are projected as leading to improvements in confidence in the use and utility of the results of the present model.

(1) Development and Maintenance of a Data Bank

The present program provides some data regarding power-plant costs and future construction plans. However, in order to keep the cost data current and to accumulate enough data from which more reliable cost-estimating relationships can be derived, a continuing effort is required. Also, such data should be gathered and placed in a form suitable for use in the model. The maintenance of such data should be an ongoing effort. The level of effort required would depend upon the extent of use of the model.

(2) Early Model Testing, Utilization, and Modifications

Beyond the efforts of the present program, it is deemed necessary to test the usefulness of the model in a variety of planning problems. Especially important will be the evaluation of data problems and the amount of effort required to perform the analyses. These initial analyses are expected to lead also to identification of needs for model modifications. These activities require management efforts to see that the user is in a position to report difficulties and to be satisfied that appropriate corrective measures are being taken; otherwise, the model will fall into disfavor and eventually not be used. To avoid this it is essential that an aggressive program of encouraging use and evaluation of the model be followed. Also, difficulties should be resolved rapidly so that the model is a viable tool of the planner. This will require more than casual efforts, and appropriate in-house or outside-contractor arrangements should be made to insure a proper conduct of this phase.

(3) Computerization

After the efforts described in (1) and (2) are under way and it appears that any difficulties have been resolved, it will then be appropriate to consider the desirability of computerizing the model. This step should be undertaken in light of

(a) Frequency of use of the model

(b) Manual efforts required for routine and repetitive data manipulation

(c) Availability of appropriate data processing personnel and equipment, in-house or on a contractual basis

(d) Anticipated requirements for further model modification.

(4) Extensions of the Model

Aside from minor modifications of the model, the use of the model in the context of R&D planning activities is expected to lead to considerations of extension of the type or scope of what is analyzed. For example, the inclusion of more detailed analysis of the impact of developing alternative SO_2-control processes might be treated as a resource (R&D funds) allocation problem amenable to solution by techniques such as "linear programming". Another possibility is the inclusion of a more sophisticated technique for the analysis of uncertainties regarding costs and utilization. Incorporation of more complex techniques, such as Monte Carlo, will probably require use of the digital computer because of more extensive requirements for calculation.

The specific next steps to be taken in a continuing program for improving the utility of the model and understanding the system which it represents are believed to be three. First, a more intensive study needs to be made of the sulfur (and sulfuric acid) market, particularly the effects which might result from alternative sources of sulfur (and sulfuric acid) coming into existence. This area is particularly important because of the sensitivity of net costs for sulfur removal and recovery to the market and "net back" price for sulfur and sulfuric acid. A simplified, gross approach was taken to establish approximate values for use in the current cost model. Now, a more sophisticated approach is needed in which other independent variables will be considered.

Second, an improved and enlarged data base would be desirable so that improvements could be made in the correlations (cost-estimating relationships) being used in computing the costs of alternatives for accomplishing SO_2 control.

Third and finally, the computation of many more cases is needed. These cases, and their alternatives, would logically be based on the utilities plans for new power-generation facilities over the next few years, as shown in Table 25 and Appendix B. Only through comparing the costs of various alternatives as they might exist in the different geographical areas would an understanding of the potential benefits and applications to be derived from each of the several SO_2-control processes be attained.

When these next steps have been accomplished, a further look into the benefits being derived should be made to assess the potential for further benefits through, for example, extensions of the model and/or computerization.

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APPENDIX A

BACKGROUND AND DISCUSSION OF MODEL METHODOLOGY AND LIMITATIONS

Background

The analysis of future costs for the application of various technical approaches to a problem is an essential part of the long-range planning problem. This type of analysis is of special interest to those concerned with the selection between competing research and development programs. The competition for available research and development funds has intensified the need for analyses directed toward early isolation of those programs with the most attractive technical potential and economic advantage. This program has been directed toward providing the long-range planner with a tool for evaluating the impact on the costs of electric power of various approaches to the control of SO_2 emissions from fossil-fuel-burning electric power plants. The intent is to provide a means for introducing the costs of SO_2 control as an additional increment of cost for electric power generation.

The approach taken has been influenced by the prior experience of groups confronted with some of the most difficult cost-analysis problems in the context of long-range planning, namely, those who identified the problems and developed the methodology for the analysis of the cost-effectiveness of future military and aerospace systems. Although this experience has influenced the approach taken to developing this model, it has been necessary to avoid a full-scale adoption of techniques developed by these groups because of the relatively small amount of effort that is considered presently appropriate for the class of problems under consideration.

Typical of the efforts in the military and aerospace field are those described in Rand reports generated in the post-World War II period. For example, Cost-Effectiveness Analysis: New Approaches in Decision-Making,(40)* contains several articles with a number of references to reports of the Rand Corporation and other organizations that deal with cost models and cost-effectiveness analyses. The article entitled "Estimating Systems Costs"(40b) points out several findings based on experience with military and aerospace cost-prediction problems. This article notes the importance of dealing with comparative costs rather than absolute accuracy of costs; in other words, the costs developed are regarded more as indices that indicate cost differences and their extent. These types of costs are distinguished from those used for, say, budgeting purposes. A major reason for taking this approach is the uncertainties of future costs. Related to this argument is the "current dollars" approach, which means that possible future inflationary effects are ignored since such effects should not normally affect the ratio of costs of competing systems.

Cost-estimating relationships (CER's) play an important role in cost models. They are used to determine costs on the basis of some physical or performance characteristic; for example, in Figure 14, initial power-plant construction costs are shown as a function of generating capacity. CER's are used in place of detailed cost estimates, such as might be generated for bidding purposes, in order to minimize the effort required to generate a preliminary cost estimate. Their exact nature depends upon the types of data available and approach taken to convert the data to a CER. Statistical techniques, such as multiple correlation, are frequently used to generate CER's, but the technique applied depends upon the nature of the available data and the level of effort that is appropriate for the required analysis. References (41) and (42) provide a discussion of the development of CER's for use in aerospace cost models. As the data base regarding power plant and SO_2-control equipment is expanded, it will be worthwhile to consider modifications of, or the use of more, CER's.

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*References are listed on page 131.

Another aspect of the background for model development is the type of financial analysis performed by electric utilities prior to making investment decisions. Reference (43) presents an example of the approach used in this type of analysis. This type of analysis places heavy emphasis on the analysis of tax implications, return on investment, discounted present worth, and other "financial factors". Although these factors are of importance to the utility charged with making proper investment decisions, they have not been given so elaborate a treatment as found in Reference (43), for example. This approach has been taken for two major reasons:

(1) The long-range planning efforts of interest are concerned with the comparison of alternatives to SO_2 control, and it is anticipated that the "financial factor" applied as a percentage of initial investment costs will be the same; hence, the application of these financial factors would not alter relative cost standing of the alternatives being considered. However, if significant differences can be anticipated in, say, taxes or depreciation charges, then the analyst must give more careful consideration to the financial-factor aspects of the problem.

(2) The complexity of the analysis is considerably reduced by taking a simplified approach to the treatment of financial factors. At this time it is felt that many of the needs for cost analyses can be met by the determination of nonrecurring, recurring, and annualized nonrecurring costs. Until a firm need is established on the basis of future problems that will be considered by the analyst, the simplified approach to financial factors – which amounts to the selection of a percentage to be applied to nonrecurring costs – is recommended.

Hardware costs are usually influenced by the rate and amount of production. A "learning curve" is frequently applied to determine the future costs of production items. Reference (41), for example, discusses techniques for incorporating "learning curve" effects into the cost analysis. This concept has not been explicitly included in the model, however, because of the nature of the initial data base and other considerations: for example, the application of learning curves requires information as to both initial production costs for equipment and the anticipated number of equipment items to be produced. Rate of production is also of interest since this influences the indirect costs applied in determining production costs. The types of data made available for power-plant and transmission-facility costs would be expected to already reflect any learning-curve effects. However, it is speculated at this time that the types of data that might become available regarding SO_2 equipment may not include such effects, unless the equipment is already in production. In this case, if the analyst hypothecates the broad application of the type of SO_2-control equipment under consideration, he may find it worthwhile to consider the possible influence of learning-curves effects. But, because of the minimum concern of this program with SO_2-control equipment costs, this aspect of the analysis is not treated further in this report.

A continual problem with cost models is the reconciliation of the time required for preparation of input data, the analysis, the interpretation of results, and the amount of time and expense feasible and desirable in long-range planning efforts. The development effort for this model has been influenced by these considerations; however, decisions as to the feasibility of pursuing costs to various levels of detail can best be made only after some model-use experience has been acquired and after decisions have been made regarding the feasible amount of effort and expense that can be incurred in the various planning exercises undertaken by the NAPCA. Comprehensive cost studies can easily require several man-years of effort, and this is usually infeasible in terms of the cost of the analysis versus the size of the budget to be committed for developments. Also, the justification for a large cost-estimating team is based on the need to analyze a continuous flow of problems. The adjustment of the costing approach to the amount of manpower that would be available for cost studies is another important consideration. Presumably the allowable costs for evaluations would be a function of the magnitude of research and development funds being allocated and the complexity of the problems being analyzed. This model has been developed with these considerations in mind.

Uncertainty and Sensitivity Considerations

If a cost figure has been obtained, the planner's next problem is to understand its uncertainty aspects. Without this insight, there is the possibility of selecting a process whose costs may actually be higher than another because the uncertainties were not analyzed. This makes it important for the analyst to examine the difference in results when reasonable variations in the cost values are allowed. The recommended approach is for the analyst to repeat the analysis using estimates of the highest or lowest possible values for the cost elements to which the results are most sensitive. For example, fuel costs may be about 80 percent of the total of annual fuel, operations, and maintenance costs. This would indicate that the results are more sensitive to a change of fuel costs in comparison with, say, a minor modification of maintenance requirements. If the results of an analysis for comparing, say, a change in fuel with incorporation of an SO_2-control process indicated that a 10 percent change in fuel costs reversed the relative costs, then the analyst would recognize the need for a more detailed analysis and improved data – or the introduction of considerations outside the scope of the cost-model analysis – before deciding which approach is superior.

When the SO_2-control process changes the heat rate of the plant, this is reflected directly in fuel costs. Also, the control process may require modifications of the power plant. When this occurs, the analyst must consider how this affects the recurring and nonrecurring costs as obtained for the power plant without SO_2 control. This requires examination of costs in more detail, and the analyst needs some insight as to the relative importance of the various subsystem and component costs. Analysis of a subsystem cost breakdown for TVA steam-production plants indicates that the nonrecurring costs for each cost element represent the following approximate percentages of total plant cost:

Subsystem	FPC Account No.	Percent
Land and land rights	310	<1
Structures and improvements	311	19
Boiler-plant equipment	312	45
Turbogenerators	314	28
Accessory electric equipment	315	6
Other power-plant equipment	316	1

The column "FPC Account No." gives the account numbers as used in Reference (2), which describes in detail the components included in each account number.

The above percentages indicate the importance of boiler-plant equipment in overall costs, so emphasis should be placed on understanding the influence of the SO_2-control process on this cost element. Note the small significance of land in total costs; however, the analyst would want to review the relative importance of this cost in those cases where the plant is located in a metropolitan area.

The recommended approach to sensitivity considerations is for the analyst to perform a preliminary estimate of all cost elements in the model, and to then base his efforts in cost refinement and "high-low" estimating upon the relative significance of each cost element in the initial effort. High-low estimates are derived from consideration of what might be reasonable for the worst and best possible areas. These types of estimates will be improved as experience is developed and the data base is improved.

A more complex model could be developed that would introduce statistical concepts into the cost estimates. Such a model development could eventually lead to the incorporation of Monte Carlo techniques that introduce random considerations into the analysis; that is, explicit recognition is given to the improbability that all costs will be high, low, or at the median at the same time [see Reference (44)]. However, such models introduce requirements for many more calculations than the present model. Such a development is left for the future – the investment required must be carefully considered in terms of needs for analysis and other considerations.

In summary, the background of other efforts in developing cost models provides a basis for considering the modeling problem at hand. These past developments have influenced the approach taken. The following factors also have had strong influence on the approach taken:

(1) The amount of effort appropriate for the types of analyses of interest

(2) The availability of cost data and the effort required to collect and/or generate new data

(3) The uncertainties associated with future cost estimates

(4) The desirability – especially from an effort-requirement standpoint – of using "sophisticated" techniques.

APPENDIX B

LISTING OF POWER GENERATION FACILITIES PLANNED AND UNDER CONSTRUCTION FOR THE TIME PERIOD 1968 THROUGH 1977

(As of March 15, 1968, with additions to July 8, 1968)

Compiled by Electrical World(45)

Unit I - Fossil-fueled steam units, 1968 through 1976 - total 108,987 Mw (pages B-2 through B-14)

Unit II - Hydro power units, 1968 through 1975 - total 11,981 Mw (pages B-15 through B-23)

Unit III - Peaking power units, 1968 through 1971 - total 5,525 Mw (pages B-24 through B-32)

Unit # I

March 15, 1968

Fossil-fueled steam power units scheduled for service in 1968 (Sheet 1of 2)

Utility	Unit	Location	Mw	Fuel	Boiler from	T-G from	Consultant	Constructor
Keystone	Keystone 2		900	Coal	C-E	W	Gilbert Assoc.	Ebasco managi
NEGEA	Canal 1	Sandwich,Mass.	560	Oil	B&W	W	Stone&Webster	Stone&Webster
PSE&G	Hudson 2		620	Coal	F-W	W	PSE&G	United Engrs.
No. Ind. PS	Bailly 8		386	Coal	B&W	GE	Sargent&Lundy	
PS Ind.	Wabash R. 6		365	Coal	C-E	W	Sargent&Lundy	
Car. P&L	Roxboro 2		650	Coal	C-E	GE	Ebasco	
Fla. P&L	C. Kennedy 2	C.Kennedy,Fla.	411	Oil, gas	F-W	GE	Bechtel	Bechtel
Comm. Edison	Kincaid 2		617	Coal	B&W	W	Sargent&Lundy	
No. States Pr.	A. King 1	Bayport,Minn.	590	Coal	B&W	W	Pioneer Serv.	Owner
Union Elec.	Sioux 2		525	Coal	B&W	GE	United Engrs.	United Engrs.
Monon. Pr.	Ft. Martin 2		540	Coal			Burns & Roe	Sand.&Porter man'g.
Mont. Pr.	Billings 2	Billings,Mon.	180	Coal	C-E	W	Bechtel	Bechtel
Pac. G&E	Moss Ldg. 7		735	Gas, oil	B&W	GE	PG&E	
Penn. P&L	Brunner Is. 3		750	Coal			Ebasco	Ebasco
PS of N.Hamp.	Merrimack 2		333	Coal	B&W	W	Jackson&Morel'd	United Engrs.
United Ill	Bridgpt Har. 3		400	Coal	C-E	GE	Ebasco	
Cinci. G&E	Beckjord 6		434	Coal	C-E	W	Sargent&Lundy	
Georgia Pr.	H. Branch 3		490	Coal	B&W	GE	Southern Serv.	
Miss. Pr.	Watson 4		250			GE	Southern Serv.	
Cent.Ill.Lt.Co.	Edwards 2		267	Coal	Riley	GE	Comm. Assoc.	
Houston L&P	Parish 4		565	Gas		GE	Ebasco	
Omaha PPD	No.Omaha 5		216	Coal	F-W	GE	Gibbs&Hill	
Long Is. Ltg.	Northport 2		390	Oil	C-E	GE	Ebasco	
Detroit Ed.	HarborBeach 1	HarborB,Mich.	114	Coal	Riley	ASEA	Bechtel	Bechtel
Detroit Ed.	St. Clair 7		527	Coal	B&W	W	Bechtel	
Ohio Edison	Sammis 6		600	Coal	B&W	W	Comm. Assoc.	
Ohio Pr.	Muskingum R. 5		615	Coal	B&W	GE	AEP Serv.Corp.	
Toledo Edison	Bayshore 4		213	Coal	B&W	W	Gibbs&Hill	
Ames, Ia.	Ames 7		35		C-E		Gibbs&Hill	
Cent. P&L	Victoria 6		258	Gas	B&W	W	Sargent&Lundy	
Gulf States	Willow Glen 3	St.Gabriel,La.	580	Gas	F-W	W	Stone&Webster	Stone&Webster
LCRA	S.Gideon 2		144	Gas		W	Gibbs&Hill	
San Antonio	Braunig 2		245	Gas	C-E		Brown & Root	

March 15, 1968

Fossil-fueled steam power units scheduled for service in 1968 (Sheet 2 of 2)

Utility	Unit	Location	Mw	Fuel	Boiler from	T-G from	Consultant	Constructor
SWPS	Nichols 3		200	Gas	C-E	GE		
West.FarmerCoop	Moreland 2		135	Gas/oil	Riley	W	LD&P	
PS of Colo.	Cherokee 4		350	Coal	C-E	GE	Stearns Roger	
Sierra Pac. Pr.	Pt. Churchill 1	Reno, Nev.	110	Gas/oil	B&W	GE	Stone&Webster	Stone&Webster
Con Edison	Arthur Kill 3		515	Coal	C-E	GE	Con Edison	
PEPCo	Benning 15	Washington,DC	275	Oil	C-E	GE	Bechtel	Bechtel
Dover, O.			22					
Springfield,Ill.	Lakeside		80					
Wisc. EP	Valley 1	Milwaukee,Wisc	140	Coal	B&W	GE	Stone&Webster	Stone&Webster
TESCo	Graham 2		375	Gas	Riley	GE	Ebasco	
Colo.Springs,Colo.	Drake 6		76					
Utah P&L	Naughton 2	Kemmerer,Wyo.	220	Coal	C-E	GE	Bechtel	Bechtel
Nevada Pr.	Gardner 2		119	Coal	F-W		StearnsRoger	
Holland, Mich.	De Young 5		29					
Jasper, Ind.			13					
Monroe, La.	Municipal 12		75					
Moorehead,Minn.	Moorehead 5		28					
Imperial Dist.	El Centro 4		75		Riley			
Pac. G&E	Geysers 4		27	Geotherm				
Minden, La.	Municipal 2		15					
Brazos R. Coop	Miller 1		81					
Pac. P&L	Green R, Wyo.		15					
Ia.Southern U.	Burlington 1		203	Coal	C-E	GE	Black & Veatch	
Norwalk, O.			18					
Ala. Elec. Coop.	Jackson 1		75					
Jamestown, NY	Carlson 6		25					
Marshfield,Wisc.	Wildwood 5		20					
Garland, Tex.	Garland 1		66		C-E			
Houston L&P	Robinson 3		565				Ebasco	
Louisiana P&L	Little Gypsy 3		560	Gas/oil	F-W	GE	Ebasco	
Opelousas, La.			26					
Ruston, La.			27					
Municipal	No. 3	Willmar,Minn.	20					
		Total	19,085 Mw					

March 15, 1968

Fossil-fueled steam power units scheduled for service in 1969 (Sheet 1 of 2)

Utility	Unit	Location	Mw	Fuel	Boiler from	T-G from	Consultant	Constructor
West Penn Pr.	Hatfield Fy 1		540	Coal	B&W	W	United Engrs.	United Engrs.
Duke Pr.	Marshall 3		671	Coal	C-E	GE	Duke Pr.	
VEPCo	Chesterfield 6	Chester, Va.	669	Coal	C-E	GE	Stone&Webster	Stone&Webster
KCP&L	Hawthorne 5		494	Coal	C-E	GE	Ebasco	
Cent. P&L	Hill 4		258	Gas/oil	B&W	W	Sargent&Lundy	
So. Car. PSA	Jefferies 3		160	Coal	Riley		Burns&Roe	
N. Eng. Pr.	Brayton Pt. 3	Somerset, Mass.	630	Coal	B&W	W	Stone&Webster	Stone&Webster
Penelec	Homer City 1	Homer City, Pa.	640	Coal	F-W	W	Gilbert Assoc.	Bechtel manag'
E. Ky. REC	Cooper 2		218	Coal	B&W	GE	Stanley	
Ind. P&L	Petersburg 2	Indianapolis	450	Coal	C-E	GE	Stone&Webster	
Kentucky Pr.	Big Sandy 2		800	Coal	F-W	GE	AEP Serv. Corp.	
Louisville G&E	Cane Run 6	Louisville,Ky.	275	Coal	C-E	GE	Pioneer Serv.	Owner
Ala. Pr.	Barry 4		360	Coal	C-E	GE	Southern Serv.	
Fla. Pr.	Crystal R. 2		510	Coal	C-E	GE	Black & Veatch	
Fla. P&L	Ft. Myers 2	Ft. Myers, Fla.	411	Oil, gas	F-W	GE	Bechtel	Bechtel
Georgia Pr.	H. Branch 4		500	Coal	B&W		Georgia Power	
Gulf States	Nelson 4	Westlake, La.	580	Gas/oil	B&W	GE	Stone&Webster	Stone&Webster
Missouri PS	Sibley 3		400	Coal	B&W	W	Gilbert Assoc.	Gilbert manag'
Okla. G&E	Horseshoe 8		435	Gas	C-E	W	Brown & Root	
W. Texas Util.	Rio Pecos 6		95	Gas/oil			Bechtel	
Muscatine, Ia.	Muscatine 8		81					
So.Cal.Edison	4 Corners 4	Farmington,NM	755	Coal	B&W	GE	Bechtel	Bechtel
O & Rock.Util.	Lovett 5	Tompkins,NY	196	Coal	B&W	GE	Bechtel	Bechtel
Big Rivers Coop	Coleman 1		160	Coal	F-W	W	Parsons	
Hoosier Coop	Petersburg 1		117	Coal	Riley		LD&P	
So.Car.PS Auth.	Jefferies 4		160	Coal	Riley	GE	Burns&Roe	Burns&Roe
Dairyland Coop.	Genoa 3/1		325	Coal	C-E	W	Burns&Roe	Burns&Roe
Natchi oches,La.			20					
Wisc. P&L	Edgewater 4		339	Coal	B&W	GE	Sargent&Lundy	
Ark. P&L	Lk.Catherine 4		530	Gas/oil	C-E	GE	Ebasco	
Assoc. Coop	T. Hill 2		290	Gas/oil	B&W	W		
Texas P&L	Tradinghouse 1		565	Gas	B&W	W	Brown & Root	
West. Pr. & G	Ft. Dodge 4		150	Gas/oil	B&W		Black & Veatch	
Wisc. EP	Valley 2	Milwaukee,Wisc	140	Coal	Riley	GE	Stone&Webster	Stone&Webster

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Fossil-fueled steam power units scheduled for service in 1969 (Sheet 2 of 3)

Utility	Unit	Location	Mw	Fuel	Boiler from	T-G from	Consultant	Constructor
So.Miss. EPA	Moselle 1	Moselle,Miss.	59					
Black Hills P&L	Wyodak 5		22				Stearns Roger	Stearns Roger
TVA	Paradise 3		1,130	Coal	B&W	GE	TVA	
Morgan C., La.			20					
So.Miss. EPA	Moselle 2	Moselle, Miss.	59					
So. Miss. EPA	Moselle 3	Moselle, Miss.	59					
Owatonna,Minn.	No. 6		20		Riley			
Rochester,Minn.	Silver Lk		56					
El Paso Elec.			108					
Opelousas, La.			26		C-E		M.Goudeau & A.	
Municipal	No. 10	Vineland, NJ	25					
		Total	14,508 Mw					

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Fossil-fueled steam power units scheduled for service in 1970 (Sheet 1 of 3)

Utility	Unit	Location	Mw	Fuel	Boiler from	T-G from	Consultant	Constructor
Pa. P&L	Conemaugh 1		900	Coal	C-E	GE	Gilbert Assoc.	Ebasco manag'g
Penelec	Homer City 2	Homer C., Pa.	640	Coal	F-W	W	Gilbert Assoc.	Bechtel manag'
Delmarva P&L	Indian R. 3		167	Coal	B&W		United Engrs.	United Engrs.
Cleveland EI	Avon 9		618	Coal	B&W	W	CEI & Sarg.&L.	
So.Cal.Edison	4 Corners 5	Farmington,NM	755	Coal	B&W	GE	Bechtel	Bechtel
Alleg. Pr. Sys.	Hatfields Fy 2		540	Coal	B&W	W	United Engrs.	United Engrs.
Col. & S.O.	Stuart 1		580	Coal	B &W	GE	Ebasco	
Duquesne Lt.	Cheswick 1	Springdale, Pa.	570	Coal	C-E	GE	Stone&Webster	Stone&Webster
Tampa Elec.	Big Bend 1		434	Coal	Riley	W	Stone&Webster	
Ill. Pr.	Baldwin 1		626	Coal	B&W	W	Sargent&Lundy	
Union Elec.	Labadie 1	Labadie, Mo.	600	Coal	C-E	W	Bechtel	Bechtel
Garland, Tex.	Garland 2	Garland, Tex.	100	Gas/oil				
PS of Okla.	Northeast 2		450	Coal	B&W	GE	Black & Veatch	
San Antonio	Braunig 3		390	Gas/oil	C-E	GE	Gibbs&Hill	
SWEPr	Wilkes 2		352	Gas	B&W	GE	Sargent&Lundy	
PEPCo	Morgantown 1	Morgantown,Md	556	Coal	C-E	W	Bechtel	Bechtel
Appalachian Pr.	Mitchell 1	Moundsville,WVa	800	Coal	F-W	W	AEP Serv. Corp	
Lansing, Mich.	Eckert 6		74					
PS of Ind.	Cayuga 1		531	Coal	C-E	W	Sargent&Lundy	
So.Ind. G&E	Warrick 4		315	Coal	B&W	GE	Ebasco	
Duke Pr.	Marshall 4		671	Coal	C-E	GE	Duke Pr.	
Georgia Pr.	Hammond 4		505	Coal	F-W	W	Southern Serv.	
Gulf Pr.	Crist 6		323	Coal	F-W	GE	Southern Serv.	
So.Car. E&G	Wateree 1		375	Coal	Riley	GE	Gilbert Assoc.	
Cent. P&L	La Palma 6		167	Gas	B&W	GE	Sargent&Lundy	
Dallas P&L	Lk. Hubbard 1		375	Gas/oil	B&W	W	Ebasco	
Empire D. E.	Asbury 1		200	Coal	B&W	W	Black & Veatch	
Gulf States	Conroe 1		250	Gas/oil	B&W	W	Brown & Root	
Houston L&P	Cedar Bayou 1		750	Gas/oil	B&W	W	Ebasco	
Springfld, Mo.	James R. 5		112	Coal	Riley		Burns&McDonnell	
Texas P&L	Valley 3		375	Gas/oil	F-W	GE		
PRWRA			410	Oil	C-E			
So.Cal.Edison	Mojave 1	Clarke C.,Nev.	755	Coal	C-E	GE	Bechtel	Bechtel
Big Rivers Coop	Coleman 21		160	Coal.	F-W		Parsons	

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Fossil-fueled steam power units scheduled for service in 1970 (Sheet 3 of 3)

Utility	Unit	Location	Mw	Fuel	Boiler from	T-G from	Consultant	Constructor
Detroit Ed.	Monroe 1		790	Coal	B&W	GE	Detroit Edison	
Hoosier E. Coop	Petersburg 2		117	Coal	Riley	GE	LD&P	
Minnkota Coop.	Center 1		237	Coal	B&W	GE	Sanderson & P.	
Austin, Tex.	Decker Cr. 1		320	Gas/oil	C-E	W	Brown & Root	
No. Ind. PS	Mitchell 11		115	Coal	B&W	GE	Sargent&Lundy	
Lafayette, La.	Bonin		100		C-E			
Louisiana P&L	9 mile 4	Westwego, La.	750	Gas/oil	C-E		Ebasco	
Wheatland Coop.		Garden C., Kan	90					
Municipal	No. 8	Columbia, Mo.	40					
Black Hills P&L	French 2		33					
		Total	18,018 Mw					

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Fossil-fueled steam power units scheduled for service in 1971 (Sheet 1 of 2)

Utility	Unit	Location	Mw	Fuel	Boiler from	T-G from	Consultant	Constructor
Pa. P&L	Conemaugh 2		900	Coal	C-E	GE	Gilbert Assoc.	Ebasco man'g
Houma, La.	Municipal 9		14		Riley		United Engrs.	
Detroit Ed.	Monroe 2		790	Coal	B&W	W		
Union Elec.	Labadie 2	Labadie, Mo.	600	Coal	C-E	W	Bechtel	Bechtel
PEPCo	Morgantown 2	Morgantown,Md	558	Coal	C-E	GE	Bechtel	Bechtel
Appalach. Pr.	Mitchell 2	Moundsville,WVa	800	Coal	F-W	GE	AEP Serv. Corp	
Jacksonville,Fla	Northside 2		268	Oil/gas	B&W	GE	Reynolds Smith	
Georgia Pr.	Etowah 1	Centersville	712	Coal		GE	Southern Serv.	
Cent. La. E.	Teche 3		361	Gas/oil	B&W	W	Sargent&Lundy	
Cent. P&L	Plant 2		240	Gas/oil	B&W	GE		
Gulf States	Conroe 2		250	Gas/oil	B&W	W	Brown & Root	
Kansas P&L	Lawrence 5		410	Coal	C-E		Black & Veatch	Austin Bldg Co.
Okla. G&E	Seminola 1		550	Gas				
So.Cal.Edison	Mojave 2	Clarke C., Nev	755	Coal	C-E	GE	Bechtel	Bechtel
Ohio Edison	Sammis 7		600	Coal	B&W	W		
Savannah E&P	Pt.Wentworth 4	Pt.Wentworth,Ga	126	Gas/oil	C-E	GE	Stone&Webster	Stone&Webster
Kansas City	Quindaro 3/2		144	Coal				
Pac. P&L	Centralia 1	Centralia,Wash	700	Coal	C-E	W	Bechtel	Bechtel man'g
Utah P&L	Naughton 3	Kemerer, Wyo,	330	Coal	C-E			
Col.&S.O.E.	Stuart 2		580	Coal	B&W	GE	Ebasco	
Kentucky Util.	E.W. Brown 3		445	Coal	C-E	W	Sargent&Lundy	
SWPS	C.Jones 1		235		C-E			
So.Cal.Edison	Ormand Beach 1	nr.Ventura, Calif.	755	Gas	F-W	GE	Bechtel	Bechtel
Houston L&P	CedarBayou 2		750					
Gulf States	Willow Glen 4	St.Gabriel,La.	580		B&W	GE	Stone&Webster	Stone&Webster
Texas Util.	Big Brown 1		575	Coal	Combustion			
Miss. P&L	Wilson 2		750	Gas/oil	B&W			
Penn. P&L	Montour 1		750	Coal	C-E	GE	Ebasco	
Tallahassee			66		F-W			
Tampa E.	Big Bend 2	No.Ruskin,Fla	434	Coal	Riley	W	Stone&Webster	Stone&Webster
Ark. E. Coop.	McClellan 1		125		Riley		LD&P	

Fossil-fueled steam power units scheduled for service in 1971 (Sheet 2 of 2)

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Utility	Unit	Location	Mw	Fuel	Boiler from	T-G from	Consultant	Constructor
Ala. Pr.	Barry 5	Bucks, Ala.	700	Coal	C-E			
Texas E S Co.	Eagle Mtn 3		375	Gas	F-W	W	Gibbs & Hill	Zachry
Sierra Pac.	Ft.Churchill 2		110		B&W		Stone&Webster	
Kansas P&L	Lawrence 5		430		C-E	W	Black & Veatch	Austin
Conn. L&P	Montville		400		C-E	GE		
So.Ind.G&E	Newberg 1		300		B&W	GE		
Indianapolis P&L	Petersburg 3		450				Stone&Webster	
Gainesville,Fla.	Municipal		66					
Lakeland, Fla.	Municipal		100		Riley			
McPherson, Kan.	Municipal		50					
PRWRA	Plant 2		410	Oil	C-E			
W. Texas Util.	Paint Crk 4		107					
PG&E	Geysers 5		53	Geotherm		Toshiba		
Appalachian Pr.	Amos 1		800	Coal			AEP Serv. Corp	
Brownsville,Tex.	Municipal		60					
New Mex.Elec.Ser			400					
		Total	19,964 Mw					

Fossil-fueled steam power units scheduled for service in 1972 (Sheet 1 of 1)

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Utility	Unit	Location	Mw	Fuel	Boiler from	T-G from	Consultant	Constructor
Cent. P&L	Plant 3		240	Gas/oil				
W. Penn Pr.	Hatfields Fy 3		540	Coal	B&W	W	United Engrs.	United Engrs.
Interstate Pr.			216					
Gulf States	Sabine 4		580	Gas/oil		GE		
Col.&S.O.E.	Stuart 3		580	Coal	B&W	GE		
Southern Co.			700			GE	Southern Serv.	
Southern Co.			700			GE	Southern Serv.	
So.Cal.Edison	Ormand Beach 2	nr.Ventura, Calif.	755	Gas	F-W	GE	Bechtel	Bechtel
PS of Ind.	Cayuga 2		531	Coal	C-E	W	Sargent&Lundy	
TVA	Cumberland 1	nr.Cumberland	1,275	Coal	B&W	Brown-Boveri	TVA	
Pac. P&L	Johnston 4		330	Coal	C-E		Ebasco	
Central Ill. Pr.	Coffeen 2		432	Coal	B&W	GE	Sargent&Lundy	
Cleveland E. I.	Eastlake		625	Coal				
SWPS	Wilkes 3		345	Gas/oil		GE		
Union Elec.	Labadie 3		600	Coal	C-E	GE		
Northeast Util.	Montville		400	Coal				
Cent. Ill. Lt.	Edwards 3		300	Coal	Riley	GE		
Tex. Util.	Big Brown 2		575	Lignite	Combustion			
San Antonio	Calaveras 1		390	Gas/oil	C-E	GE	Black & Veatch	
L.Colo.R.Auth.	S. Gideon 3		325	Gas/oil	C-E	GE		
Louisville G&E	Kosmos 1		350	Coal	C-E	GE	Pioneer Serv.	Owner
LADW&P	El Segundo		450				LADW&P	
Pacific G&E	Pittsburg 7		750	Gas/oil	C-E	W		
Gulf States	Sabine 4		580			GE		
Pa. P&L	Strawberry R 1		765			GE		
Brazos E. Coop			125					
Denton, Tex.			75					
El Paso Elec.	Newman 4		150					
Fla. P&L			730		F-W		Bechtel	
Fremont, Neb.			55					
Lansing, Mich.	Municipal		150					
PRWRA			450	Oil	C-E			
Iowa PS	Neal 2		325					
Appalachian Pr.	Amos 2		800	Coal			AEP Serv.Corp.	
LADW&P	Scattergood		450	Gas/oil				
		Total	16,644 Mw					

Fossil-fueled steam power units scheduled for service in 1973 (sheet 1 of 1)

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Utility	Unit	Location	Mw	Fuel	Boiler from	T-G from	Consultant	Constructor
Ind. P&L			450					
So.Car.E&G	Plant 1		600				Gilbert Assoc?	
Illinois Pr.	Baldwin 2		600					
Kansas G&E	Evans 3		380	Gas/oil				
Union Elec.	Labadie 4		600	Coal	C-E	GE		
NEES	SalemHarbor 4		450			GE		
TVA	Cumberland 2	nr.Cumberland	1,275	Coal	B&W	Brown-Boveri	TVA	
Col. & S.Ohio	Conesville 4		600		Riley	W	Black & Veatch	
Union Elec.	Sioux 3		600	Coal				
Allegheny PS	Allegheny 1		650	Coal		W	Gibbs & Hill	Gibbs & Hill
Ill. Power	Baldwin 2		600					
Unit. Ill.	Bridgeport 3		400					
Colo. Springs	Municipal		106					
Gulf States			750					
Independence,Mo	Municipal		90					
KCP&L			400					
Utah P&L			440					
Okla. G&E	Seminole 2		550			W		
Mid South			450				Bechtel	
Kan.G&E & KCP&L		La Cygne,Kan.	840	Coal				
		Total	10,831 Mw					

Fossil-fueled steam power units scheduled for service in 1974 (sheet 1 of 1)

March 15, 1968

Utility	Unit	Location	Mw	Fuel	Boiler from	T-G from	Consultant	Constructor
Union Elec.	Sioux 4		600	Coal				
Allegheny PS	Allegheny 2		650	Coal		W	Gibbs & Hill	Gibbs & Hill
TVA	Cumberland 2		1,300		B&W	Brown-Boveri	TVA	
Springfield, Mo.	James R. 6		112					
Basin Elec.	Olds 2		400					
Cent. La. Elec.			440					
Garland, Tex.			150					
KC Municipal	Municipal		150					
Kentucky Util.			450					
NOPSI			750					
PS New Mex.								
PS Okla.			600					
Tampa Elec.			600					
Salt R. Project	Navaho 1		750					
Texas P&L			785			GE		
		Total	7,737 Mw					

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Fossil-fueled steam power units scheduled for service in 1975 (sheet 1 Of 1)

Utility	Unit	Location	Mw	Fuel	Boiler from	T-G from	Consultant	Constructor
Salt R. Project	Navajo 2		750			GE		
Pac. P&L	Centralia 2		700	Coal	C-E	W		
		Total	1,450 Mw					

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Fossil-fueled steam power units scheduled for service in 1976 (sheet 1 of 1)

Utility	Unit	Location	Mw	Fuel	Boiler from	T-G from	Consultant	Constructor
Salt R. Project	Navajo 3		750			GE		

Unit # II

Hydro power units scheduled for service in 1968 (Sheet 1 of 2)

March 15, 1968

Utility	Unit	Location	Mw	Fuel	Prime mvr from	Gen. from	Consultant	Constructor
Sabine R.Auth.	Toledo Bend 1		42	Hydro				
Sabine R.Auth.	Toledo Bend 2		42	Hydro				
US Engrs.	Millers Fy 1		25	Hydro				
Idaho Pr.	HellsCanyon 2		142	Hydro				
Idaho Pr.	HellsCanyon 3		142	Hydro				
US Engrs.	Day 1		155	Hydro				
US Engrs.	Day 2		155	Hydro				
US Engrs.	Day 3		155	Hydro				
US Engrs.	Day 4		155	Hydro				
US Engrs.	Day 5		155	Hydro				
US Engrs.	Day 6		155	Hydro				
Calif.Dept.Water	Oroville 3		PS117	Hydro				
Calif.Dept.Water	Oroville 4		PS 98	Hydro				
Calif.Dept.Water	Oroville 5		PS117	Hydro				
Ala. Pr.	Lay Dam 1		29	Hydro				
Ala. Pr.	Lay Dam 2		29	Hydro				
Ala. Pr.	Lay Dam 3		29	Hydro				
Ala. Pr.	Lay Dam 4		29	Hydro				
DouglasCoPUD 1	Wells 8		88	Hydro				
DouglasCoPUD	Wells 9		88	Hydro				
DouglasCoPUD	Wells 10		88	Hydro				
Tacoma, Wash.	Mossyrock 1		164	Hydro				
Tacoma, Wash.	Mossyrock 2		164	Hydro				
Calif.Dept.Water	Thermalito 1		PS 33	Hydro				
Calif.Dept.Water	Thermalito 2		PS 28	Hydro				
Calif.Dept.Water	Thermalito 3		28	PS Hydro				
Grand R. Auth.	Salina 1		43	PS Hydro				
Grand R. Auth.	Salina 2		43	PS Hydro				
Grand R. Auth.	Salina 3		43	PS Hydro				
US Engrs.	Narrows 3		9	Hydro				
US Engrs.	Foster 1		12	Hydro				
US Engrs.	Foster 2		12	Hydro				
Ala. Pr.	Holt Dam 1		40	Hydro				
US Engrs.	Priest 1		28	Hydro				
USBR	Fontenelle		10	Hydro				

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Hydro power units scheduled for service in 1968 (Sheet 2 of 2)

Utility	Unit	Location	Mw	Fuel	Prime mvr from	Gen. from	Consultant	Constructor
Douglas PUD	Wells 7		89	Hydro				
Calif.Dept.Water	Oroville 1		117	PS Hydro				
Calif.Dept.Water	Oroville 2		98	PS Hydro				
SMUD	Camino 2		68	Hydro				
SMUD	White Rk 1		100	Hydro				
SMUD	White Rk 2		100	Hydro				
USBR	San Luis 1		53	PS Hydro				
USBR	San Luis 2		53	PS				
		Total	3,370 Mw					

Hydro power units scheduled for service in 1969 (Sheet 1 of 1)

March 15, 1968

Utility	Unit	Location	Mw	Fuel	Prime mvr from	Gen. from	Consultant	Constructor
US Engrs.	Broken Bow 1		50	Hydro				
US Engrs.	Day 7		155	Hydro				
US Engrs.	Day 8		155	Hydro				
US Engrs.	Day 9		155	Hydro				
US Engrs.	Day 10		155	Hydro				
Calif.Dept. W	Oroville 6		98	PS Hydro				
US Engrs.	Day 11		155	Hydro				
USBR	Morrow Pt. 2		60	Hydro				
Penelec	Seneca 1		175	PS Hydro				
Penelec	Seneca 2		175	PS Hydro				
Penelec	Seneca 3		30	Hydro				
US Engrs.	Millers Fy 2		25	Hydro				
US Engrs.	Millers Fy 3		25	Hydro				
USBR	Morrow Pt. 1		60	Hydro				
US Engrs.	L.Monument 1		155	Hydro				
US Engrs.	L.Monument 2		155	Hydro				
US Engrs.	L.Monument 3		155	Hydro				
San Francisco	N.Moccasin 1		51	Hydro				
San Francisco	N.Moccason 2		51	Hydro				
PG&E	Belden 1		117	Hydro				
		Total	2,157 Mw					

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Hydro power units scheduled for service in 1970 (Sheet 1 of 1)

Utility	Unit	Location	Mw	Fuel	Prime mvr from	Gen. from	Consultant	Constructor
US Engrs.	Lit. Goose 1		155	Hydro				
US Engrs.	Lit. Goose 2		155	Hydro				
US Engrs.	Lit. Goose 3		155	Hydro				
US Engrs.	Day 12		155	Hydro				
US Engrs.	Day 13		155	Hydro				
US Engrs.	Day 14		155	Hydro				
TVA	Tims Ford		40	Hydro				
Yuba R. Water	Yuba New Col.1		142	Hydro				
Yuba R. Water	Yuba New Col.2		142	Hydro				
Yuba R. Water	YubaNewNarrow		47	Hydro				
JCP&L	Longwood Val.1		PS 43	Hydro				
JCP&L	Longwood Val.2		PS 43	Hydro				
JCP&L	Longwood Val.3		PS 43	Hydro				
US Engrs.	Broken Bow 1		50	Hydro				
US Engrs.	Kerr 1		28	Hydro				
US Engrs.	Kerr 2		28	Hydro				
US Engrs.	Kerr 3		28	Hydro				
US Engrs.	Kerr 4		28	Hydro				
US Engrs.	Stockton 1		45	Hydro				
Duke Pr.	Keowee 1		70	Hydro	A-C			
Duke Pr.	Keowee 2		70	Hydro	A-C			
		Total	1,777 Mw					

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Hydro power units scheduled for service in 1971 (Sheet 1 of 1)

Utility	Unit	Location	Mw	Fuel	Prime mvr from	Gen. from	Consultant	Constructor
US Engrs.	Hull 2		33	Hydro				
US Engrs.	Hull 3		33	Hydro				
US Engrs.	Ozark 1		20	Hydro				
US Engrs.	Ozark 2		20	Hydro				
US Engrs.	Ozark 3		20	Hydro				
US Engrs.	Hull 1		33	Hydro				
US Engrs.	DeGray 1		PS 40	Hydro				
US Engrs.	DeGray 2		PS 28	Hydro				
SMUD	Loan Lake		78	Hydro				
Turlock Dist.	New Don P 1		50	Hydro				
Turlock Dist.	New Don P 2		50	Hydro				
Turlock Dist.	New Don P 3		50	Hydro				
Northeast U.	Northfield 1		250	PS Hydro				
Northeast U.	Northfield 2		250	PS Hydro				
Northeast U.	Northfield 3		250	PS Hydro				
Northeast U.	Northfield 4		250	PS Hydro				
Chelan PUD 1	Rocky Reach 8		150	Hydro				
Chelan PUD	Rocky Reach 9		150	Hydro				
Chelan PUD	Rocky Reach 10		150	Hydro				
Chelan PUD	Rocky Reach 11		150	Hydro				
		Total	2,055 Mw					

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Hydro power units scheduled for service in 1972 (sheet 1 of 1)

Utility	Unit	Location	Mw	Fuel	Prime mvr from	Gen. from	Consultant	Constructor
US Engrs.	W.Point Ga		36	Hydro				
US Engrs.	W.Point Ga		36	Hydro				
US Engrs.	Ozark 4		20	Hydro				
US Engrs.	Ozark 5		20	Hydro				
US Engrs.	Webbers Falls1		PS 20	Hydro				
US Engrs.	Webbers Falls2		PS 20	Hydro				
US Engrs.	Carters 1		125	Hydro				
US Engrs.	Carters 2		125	Hydro				
		Total	402Mw					

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Hydro power units scheduled for service in 1973 (Page 1 of 1)

Utility	Unit	Location	Mw	Fuel	Prime mvr from	Gen. from	Consultant	Constructor
US Engrs.	Webbers Fls 3		PS 20	Hydro				

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Hydro power units scheduled for service in 1974 (Page 1 of 1)

Utility	Unit	Location	Mw	Fuel	Prime mvr from	Gen. from	Consultant	Constructor
NEES		Rowe, Mass.	600	PS Hydro				
Duke Pr.	Jocassee 1		150	PS Hydro	A-C			
Duke Pr.	Jocassee 2		150	PS Hydro	A-C			
		Total	900 Mw					

Hydro power units scheduled for service in 1975 (Page 1 of 1)

March 15, 1968

Utility	Unit	Location	Mw	Fuel	Prime mvr from	Gen. from	Consultant	Constructo
Duke Pr.	Jocassee 3		150	PS Hydro	A-C			
Duke Pr.	Jocassee 4		150	PS Hydro	A-C			
VEPCo	Marble Valley		1,000					
		Total	1,300 Mw					

Unit # III

Peaking power units scheduled for service in 1968 (Sheet 1 of 4)

March 15, 1968
Revised July 8, 1968

Utility	Unit	Location	Mw	Fuel	Prime mvr from	Gen. from	Consultant	Constructo
Fla. Pr.		Central Fla.	GT5x33	Gas/oil		Worthington		
No.Ind.PS	Mitchell 9B		GT 17					
No.Ind.PS	Mitchell 9C		GT 17					
Penn. P&L	Suburban		GT 31					
Consumers Pr.	Campbell A		GT 21					
Consumers Pr.	Morrow A		GT 20					
Detroit Edison	Monroe		D 14					
Fla. P&L	--		D 14					
Fla. P&L	--		D 14					
Freeport, NY			D 10					
Freeport, NY			D 10					
PEPCo	Buzzard Pt.		GT 17		GE			
PEPCo	Buzzard Pt.		GT 17		GE			
PEPCo	Buzzard Pt.		GT 17		GE			
PEPCo	Buzzard Pt.		GT 17		GE			
PEPCo	Buzzard Pt.		GT 17		GE			
PEPCo	Buzzard Pt.		GT 17		GE			
PEPCo	Buzzard Pt.		GT 17		GE			
PEPCo	Buzzard Pt.		GT 17		GE			
PEPCo	Buzzard Pt.		GT 17		GE			
PEPCo	Buzzard Pt.		GT 17		GE			
PEPCo	Buzzard Pt.		GT 17		GE			
PEPCo	Buzzard Pt.		GT 17		GE			
PEPCo	Buzzard Pt.		GT 17		GE			
PEPCo	Buzzard Pt.		GT 17		GE			
PEPCo	Buzzard Pt.		GT 17		GE			
PEPCo	Buzzard Pt.		GT 17		GE			
Detroit Edison	Harbor Beach		D 4					
North. States	Albany		D 5					
Duke Pr.	Dan R 4C		GT 34					
Duke Pr.	Dan R 5C		GT 34					
Duke Pr.	Lee 5C		GT 34					
Duke Pr.	Lee 6C		GT 34					
So.Car. E&G	1		GT 16					
So.Car. E&G	2		GT 16					

Peaking power units scheduled for service in 1968 (Sheet 2 of 4)

March 15, 1968

Utility	Unit	Location	Mw	Fuel	Prime mvr from	Gen. from	Consultant	Constructo
Ia-Ill G&E	Riverside		GT 16					
Ia-Ill G&E	Riverside		GT 16					
Ia-Ill G&E	Riverside		GT 16					
Ia-Ill G&E	Riverside		GT 16					
Springfield,Mo.	Main St. GT1		GT 16					
Ind.&Mich. E	Indiana 1		GT 17					
Ind.&Mich. E	Indiana 2		GT 17					
Ind.&Mich. E	Indiana 3		GT 17					
Con Edison	59th St.		GT 21					
Con Edison	59th St.		GT 21					
Con Edison	Hudson Ave.		GT 21					
Con Edison	Hudson Ave.		GT 21					
Con Edison	Indian Pt.		GT 25					
Con Edison	Kent Ave.		GT 15					
Con Edison	Kent Ave.		GT 15					
Con Edison	74th St.		GT 21					
Con Edison	74th St.		GT 21					
Con Edison	Waterside		GT 15					
Delmarva P&L		Crisfield,Md.	D 10					
Delmarva P&L		Delaware City	GT 16					
Delmarva P&L		Vienna, Md.	GT 16					
Northeast Util.	W.Springfld 4		GT 21					
Rochester G&E			GT 19					
Rochester G&E			GT 19					
Consumers Pr.	Gaylord 5		GT 21					
Consumers Pr.	Weadock A		GT 21					
Consumers Pr.	Whiting A		GT 21					
Detroit Edison	St Clair		GT 21					
Louisville G&E		Louisville,Ky	GT 16					
Louisville G&E			GT 16					
PS of Ind.	Wabash Peak.		GT 19					
PS of Ind.	Wabash Peak.		GT 19					
PS of Ind.	Wabash Peak.		GT 19					
PS of Ind.	Wabash Peak.		GT 16					
Carolina P&L	Robinson		GT 16					

Peaking power units scheduled for service in 1968 (Sheet 3 of 4)

March 15, 1968

Utility	Unit	Location	Mw	Fuel	Prime mvr from	Gen. from	Consultant	Constructo
VEPCo	Possum Pt.		GT 15					
VEPCo	Possum Pt.		GT 15					
VEPCo	Possum Pt.		GT 15					
VEPCo	Possum Pt.		GT 15					
VEPCo	Possum Pt.		GT 15					
VEPCo	Possum Pt.		GT 15					
Municipal	Yazoo City 5	Yazoo C,Miss	GT 14					
Comm. Edison	Crawford 31-1		GT 17					
Comm. Edison	Crawford 31-2		GT 17					
Comm. Edison	Crawford 31-3		GT 17					
Comm. Edison	Crawford 31-4		GT 17					
Comm. Edison	Crawford 32-1		GT 17				Sargent&Lundy	
Comm. Edison	Crawford 32-2		GT 17					
Comm. Edison	Crawford 32-3		GT 17					
Comm. Edison	Crawford 32-4		GT 17					
Comm. Edison	Crawford 33-1		GT 17					
Comm.Edison	Crawford 33-2		GT 17					
Comm.Edison	Crawford 33-3		GT 17					
Comm.Edison	Crawford 33-4		GT 17					
Comm.Edison	Fisk 31 1&2		GT 76				Sargent&Lundy	
Comm. Edison	Fisk 32 1&2		GT 76					
Comm. Edison	Fisk 33 1&2		GT 76					
Comm. Edison	Fisk 34 1&2		GT 76					
Macon, Mo.	Macon		D 5					
Peru, Ill.	Peru 1 GT		GT 12					
SWEP	Lone Star 2		GT 16					
SWEP	Lone Star 3		GT 16					
SWEP	Lone Star 4		GT 16					
SWPS	Guymon 1		GT 15					
DetroitLk,Minn	Detroit Lk 4		GT 11					
San D G&E	San Diego 1	Encina	GT 20	Gas/oil	GE	GE	Pioneer Serv.	Owner
San D G&E	San Diego 2	El Cajon Sub.	GT 20	Gas/oil	GE	GE	Pioneer Serv.	Owner
San D G&E	San Diego 3	Division Sub.	GT 20	Oil	GE	GE	Pioneer Serv.	Owner
San D G&E	San Diego 4	Kearney Sub.	GT 20	Gas/oil	GE	GE	Pioneer Serv.	Owner
Col. & S.O.E.	Walnut 7		GT 29					

March 15, 1968

Peaking power units scheduled for service in 1968 (Sheet 4 of 4)

Utility	Unit	Location	Mw	Fuel	Prime mvr from	Gen. from	Consultant	Constructor
Col. & S.O.E.	Walnut 8		GT 29					
Dayton P&L	Hutchings		GT 29					
Dayton P&L	Monument		D 14					
Dayton P&L	Sydney		D 14					
Louisville G&E	Paddys Run 12		GT 29					
Gainesville,Fla.	Gainesville 1		GT 15					
Gainesville,Fla.	Gainesville 2		GT 15					
Lk.Superior Pr	Flambeau 1		GT 20		H.Vogt(waste ht)	W	Sargent&Lundy	
HarrisonvilleMiss			D 4					
Hartford E L	Franklyn 1		GT 21					
PS of N.H.	Merrimack 3		GT 21					
PS of N.H.	White Lk 1		GT 21					
Grand Is.,Nebr.	Burdick 3		GT 15					
No. Ind. PS	Bailly 10		GT 34					
Car. P&L	Roxboro		GT 16					
Jacksonville,Fla			GT 15					
Jacksonville,Fla			GT 15					
Cedar Falls, Ia			GT 22					
Comm. Edison	Waukegan 31 1&2	Waukegan,Ill	GT 76	Oil	Worthington	Elec. Mach.	Pioneer Serv.	Worthington
Comm. Edison	Waukegan 32 1&2	Waukegan,Ill	GT 76	Oil	Worthington	Elec. Mach.	Pioneer Serv.	Worthington
Wisconsin EP	Lakeside 21		GT 18					
Wisconsin EP	Lakeside 22		GT 18					
Wisconsin EP	Oak Creek 9		GT2x20	Oil/gas		Westinghouse		
Miss. P&L	Brown 5		GT 12					
Thibodaux,La.	Thibodaux 12		D 6					
PS of Colo.	Cherokee		D 6					
Tampa Elec.	Big Bend		GT 18					
Tampa Elec.	Gannon		GT 18					
		Total	2,864 Mw					

March 15, 1968
Revised July 8, 1968

Peaking power units scheduled for service in 1969 (Sheet 1 of 3)

Utility	Unit	Location	Mw	Fuel	Prime mvr from	Gen. from	Consultant	Constructor
Boston Edison	No. 1		GT 17		AEI			
Boston Edison	No. 2		GT 17		AEI			
Boston Edison	No. 3		GT 17		AEI			
Boston Edison	No. 4		GT 17		AEI			
Boston Edison	No. 5		GT 17		AEI			
Boston Edison	No. 6		GT 17		AEI			
Conn. L&P	No. 1		GT 21					
Conn. L&P	No. 2		GT 21					
Balt. G&E	Westport		GT 132					
Conn. L&P	No. 3		GT 21					
PS of N.H.	Merrimack 4		GT 19					
Atlantic City E.		AtlanticCity	GT 20					
Atlantic City E.		AtlanticCity	GT 20					
Atlantic City E.		AtlanticCity	GT 20					
Northeast Util.	Branford 1		GT 21					
Northeast Util.	Enfield 1		GT 21					
Northeast Util.	Tunnel 3		GT 21					
Northeast Util.	Doreen 1		GT 21					
Northeast Util.	Woodland Rd 1		GT 21					
So.Cal.Edison	Alamitos 7		GT 121					
So.Cal.Edison	Huntington B.5		GT 121					
So.Cal.Edison	Etiwanda 3		GT 121					
Penn. P&L	Fishbach 1		GT 19					
Penn. P&L	Fishbach 2		GT 19					
Penn. P&L	W. Shore 1		GT 19					
Penn. P&L	W. Shore 2		GT 19					
Penn. P&L	Lock Haven 1		GT 19					
Col. & S.O.E.	Stuart		D 11					
Kansas City,Kan	Quindaro 3		GT 17					
So.Cal.Edison	Stauffer Chem.		GT 12					
So.Miss. EPA	Moselle		GT 14					
So.Miss. EPA	Moselle		GT 14					
So.Miss. EPA	Moselle		GT 14					
Louisville G&E	Riverside 1		GT 16					
Phila. Elec.	Chester		GT 20					

March 15, 1968

Peaking power units scheduled for service in 1969 (Sheet 2 of 3)

Utility	Unit	Location	Mw	Fuel	Prime mvr from	Gen. from	Consultant	Constructor
Phila. Elec.	Chester		GT 20					
Phila. Elec.	Chester		GT 20					
Phila. Elec.	Delaware		GT 20					
Phila. Elec.	Delaware		GT 20					
Phila. Elec.	Delaware		GT 20					
Phila. Elec.	Delaware		GT 20					
Phila. Elec.	Southwark		GT 20					
PEPCo			GT 17					
PEPCo			GT 17					
PEPCo			GT 17					
PEPCo			GT 17					
PEPCo			GT 17					
PEPCo			GT 17					
PEPCo			GT 17					
PEPCo			GT 17					
PSE&G	Kearney 10		GT 140					
PSE&G	Kearney 11		GT 140					
Jacksonville,Fla			GT 16					
Jacksonville,Fla.			GT 16					
Jacksonville,Fla.			GT 16					
Jacksonville,Fla.			GT 16					
Municipal		Kaukauna,Wis.	GT 17					
Iowa PS		Chas.City,Ia	GT 34					
North. States	No. 1		GT 20					
North. States	No. 2		GT 20					
North. States	No. 3		GT 20					
North. States	No. 4		GT 20					
West. Mass.	Silver Lake		GT 19					
West. Mass.	Silver Lake		GT 19					
West. Mass.	Silver Lake		GT 19					
West. Mass.	Silver Lake		GT 19					
Municipal	Substa. J-1	Independ,Mo.	GT 15					
Municipal	Substa. J-2	Independ,Mo.	GT 15					
Comm. Edison	Joliet 31-1		GT 18					
Comm. Edison	Joliet 31-2		GT 18					

Peaking power units scheduled for service in 1969 (Sheet 3 of 3)

March 15, 1968

Utility	Unit	Location	Mw	Fuel	Prime mvr from	Gen. from	Consultant	Constructor
Comm. Edison	Joliet 31-3		GT 18					
Comm. Edison	Joliet 31-4		GT 18					
Comm. Edison	Joliet 32-1		GT 18					
Comm. Edison	Joliet 32-2		GT 18					
Comm. Edison	Joliet 32-3		GT 18					
Comm. Edison	Joliet 32-4		GT 18					
Comm. Edison	Sabrooke 31-1		GT 18					
Comm. Edison	Sabrooke 31-2		GT 18					
Comm. Edison	Sabrooke 31-3		GT 18					
Comm. Edison	Sabrooke 31-4		GT 18					
		Total	2,130 Mw					

Peaking power units scheduled for service in 1970 (Sheet 1 of 1)

March 15, 1968

Utility	Unit	Location	Mw	Fuel	Prime mvr from	Gen. from	Consultant	Constructor
Balt. G&E	Riverside		GT 132					
So.Cal.Edison	Mandalay 5		GT 121					
Long Is. Ltg.	Barrett		GT 21					
Long Is. Ltg.	Barrett		GT 21					
Long Is. Ltg.	Barrett		GT 21					
Long Is. Ltg.	Barrett		GT 21					
Long Is. Ltg.	Barrett		GT 21					
Long Is. Ltg.	Barrett		GT 21					
Long Is. Ltg.	Barrett		GT 21					
Long Is. Ltg.	Barrett		GT 21					
Wisc. E P	Point Beach		GT 20					
PEPCo	Morgantown		GT 17					
PEPCo	Morgantown		GT 17					
		Total	475 Mw					

March 15, 1968

Peaking power units scheduled for service in 1971 (Sheet 1 of 1)

Utility	Unit	Location	Mw	Fuel	Prime mvr from	Gen. from	Consultant	Constructor
Long Is. Ltg.	Shoreham		GT 56					